

Study of Automatic Control System to Maintain
Constant Percentage SO₂ Retention in a
Pressurized FBC

General Electric Co.
Schenectady, NY

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STUDY OF AUTOMATIC CONTROL SYSTEM TO MAINTAIN
CONSTANT PERCENTAGE SO₂ RETENTION IN A PRESSURIZED FBC

by

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ABSTRACT

The Clean Air Act amendments of 1977 indicate that future emission standards for SO_2 should be based upon a percentage reduction (comparing sulfur emissions with sulfur feed). In a pressurized fluidized-bed (PFB) boiler, sulfur feed (as determined by coal sulfur content and feed rate), and sulfur removal effectiveness (as determined by the reactivity and feed rate of dolomite/limestone sorbent) will vary continually during PFB plant operation. The purpose of this study was to assess the feasibility of employing some type of automatic control system which could maintain a constant percentage sulfur removal in a PFB system as variations occur in key variables, such as coal sulfur content and sorbent reactivity.

A transient model of a pressurized fluidized bed (PFB) power plant has been developed for studying methods of controlling bed SO_2 absorption characteristics. To accomplish this, the transient equation for the population distribution as a function of size and utilization was solved. The model uses TCA rate data for 1337 dolomite as a function of size, utilization and temperature. The kinetic data is integrated over the instantaneous population distribution to determine the instantaneous SO_2 absorption rate constant.

The results of the model compare favorably to steady state and transient data acquired from the Exxon miniplant PFB. It has been found that the time required to change from one steady state operating point to another is a function of the size of the change and the direction of change. This effect can be related to the rate of sulfation of dolomite particles as a function of utilization.

It was also found that in spite of rapid changes in sulfur input to the bed, the change in retention is very slow. Retention changes slowly because the rate of the sulfur capture reaction in the bed is first order with respect to SO_2 concentration and also because the inventory of dolomite within the bed represents a large inertia.

Since retention changes slowly, it can easily be controlled. However, measuring only the concentration of SO_2 in the stack gas is inadequate for this purpose. To control retention, the amount of sulfur input to the bed must also be monitored.

A review of available and developmental processes for monitoring the sulfur content of the fuel is included in this study. From this review it was judged that the rate of sulfur input to the bed could be monitored best by a system based on prompt neutron activation analysis of part of the coal feed. Such a system is now undergoing development.

It was found that the slow changes in retention due to changes in sulfur content of the coal could be practically eliminated if the feed rate of absorbent to the bed is modulated in proportion to the rate of sulfur input to the bed. This method of control was incorporated into a preferred control system along with a feedback signal of retention. The incorporation of this feedback signal adequately compensates for variations in reactivity of the absorbent.

The preferred control system will significantly reduce the amount of dolomite required to insure compliance with the Clean Air Act. Consequently, significant cost savings are possible. Application of the results of this study to an AFB is discussed.

This report was submitted in fulfillment of contract #68-02-3131 by the Energy Systems Programs Department of the General Electric Company under the sponsorship of the U.S. Environmental Protection Agency. This report covers a period from September 29, 1978 to January 29, 1980 and work was completed on December 15, 1980.

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LIST OF SYMBOLS

a	Parameter describing excess air, unitless
A	Attrition rate, kg/s; also area of heat transfer to steam tubes, m^2
A_b	Area of bed, m^2
Ar	Archimedes Number, $\frac{g x^3 \rho_G (\rho_S - \rho_G)}{\mu_G^2}$
b	Weight of the bed, kg
c_1, c_2, c_3	Constants
C_p	Specific heat of bed, J/kg- $^{\circ}C$
C_s	Concentration of sulfur
ΔH_R	Heat of reaction, kW
ΔT_{lm}	Log mean temperature difference between bed temperature and steam, $^{\circ}F$
D_{SA}	Normalized coal particle concentration
dt	Calculation interval, seconds
E	Elutriation rate, kg/s
η_L	System losses stated as fraction of total available energy
F	Feed rate of freshly calcined dolomite, kg/s
f_d	Fraction of particles within the bed smaller than a given size
f_j	Temperature dependence function of rate constant
f_s	Sulfur fraction in coal
g	Gravity, 9.81 m/s^2
$G(z)$	Sulfur generation within bed
h	Coefficient of heat transfer, $W/m^2-^{\circ}C$
$H_{in,i}$	Enthalpy of species i entering bed, J/kg

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LIST OF SYMBOLS (CONTINUED)

$H_{out,j}$	Enthalpy of species j leaving bed, J/kg
H_t	Expanded bed height at operating conditions, m
H_{fC}	Heat of formation of CO_2 , J/kg
H_{fS}	Heat of formation of SO_2 , J/kg
H_{tmf}	Expanded bed height at minimum fluidization velocity, m
J	Gas flow through the bed, kg/s
k_l	Absorption rate constant, s^{-1}
k_e	Attrition rate constant, m^{-1}
k_h	Fractional change in h to account for differences in bed temperature from 1227 K
k_{ij}	Reactivity of particles of specific size and utilization, $kg\text{-mole}/m^3\text{-s}$
M_b	Mass of bed, kg
M_g	Molecule weight of the gas
$\dot{m}_{in,i}$	Mass flow rate into bed of species i, kg/s
$\dot{m}_{out,j}$	Mass flow rate out of bed of species j, kg/s
m_{ij}	Mass of particles of specific size and utilization, kg
M_s	Molecular weight of sulfur, kg/kg mole
μ	Viscosity, $kg/m\text{-s}$
n	Number of moles
N	Calcium distribution
O	Bed solids offtake rate, kg/s
P_{FB}	Gas pressure in the fluidized bed, kPa
P_{Ti}	Gas pressure at the turbine inlet nozzle, kPa
ρ_g	Gas density, g/m^3
ρ_s	Solids density, g/m^3
$\bar{Q}_s$	Power available to steam, kW

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LIST OF SYMBOLS (CONTINUED)

r	Retention, percent
R	Universal gas constant = 0.08205 l-atm/g-mole K
R_e	Reynolds number, unitless
R_1	Rate of sulfur entering bed, moles/s
R_o	Rate of sulfur leaving bed, moles/s
$[SO_2]$	Concentration of SO_2
t	Time, seconds
$t_{1/2}$	Time of half calcination, seconds
$t_{c-1/2}$	Time to heat up to half calcination temperature, seconds
T_{BED}	Temperature of the bed, $^{\circ}C$
t_{CAL}	Time of total calcination, seconds
T_{Ti}	Gas turbine firing temperature, $^{\circ}C$
$T_t, T_{t+\Delta t}$	Bed temperature at times t and $t+\Delta t$, $^{\circ}C$
u	Utilization, percent
U_e	Effective gas velocity, m/s
U_{mf}	Minimum fluidization velocity, m/s
U_{sg}	Superficial gas velocity, m/s
U_t	Terminal particle velocity, m/s
V	Volume (expanded bed), m^3
W_C	Coal flow into bed, kg/s
W_H	Free hydrogen in coal, kg/s
W_{PFB}	Flow leaving the combustor, kg/s
W_S	Sulfur input rate, kg/s
W_{Ti}	Gas flow through the turbine inlet nozzle, kg/s
x	Dolomite particle size, microns

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TYPING GUIDE SHEET

SECTION 1

SUMMARY

The Clean Air Act amendments of 1977 indicate that the future emission standards for SO_2 should be based upon a percentage reduction. In a conventional power plant using flue gas desulfurization (FGD), percentage reduction of sulfur can, in principle, easily be monitored and controlled. Sulfur dioxide (SO_2) concentration can readily be measured before and after the FGD unit to determine the percentage of SO_2 absorbed by the process. Because there are no components that inherently have slow response, control of the system is relatively straightforward.

In the future, power plants employing a fluidized bed will encounter a different situation. Instead of simply monitoring gas concentrations to determine the percentage reduction, coal sulfur content and feed rate will need to be monitored. Moreover, the mass of absorbent in a bed represents a large inertia that must be controlled. Changes in the reactivity of the sorbent feed also will affect the control system.

This study has examined the control of sulfur capture in fluidized beds with emphasis placed on pressurized fluidized beds. Specifically, this study has examined how changes in load and coal sulfur content affect sulfur capture in a pressurized fluidized bed combustor. In addition, various methods of controlling bed sulfur absorption properties that minimize sorbent usage and maintain a constant percent sulfur removal were examined.

The method chosen to perform this work was to develop a transient model for the PFB power plant, to validate the model through comparison with experimental data, and to use this model to evaluate various control strategies. Emphasis has been placed on phenomenological modeling of the sulfur capture processes within the pressurized fluidized bed. However, the model also includes representations of all the major equipment in the PFB/combined cycle power plant, such as gas and steam turbines.

The transient rate of sulfur capture is determined from the transient distribution of dolomite particles within the fluidized bed as a function of size and utilization. The model solves for this transient distribution by integrating this distribution with chemical rate constants (which are also a function of size and utilization); the instantaneous rate of sulfur adsorption is obtained. Comparison of the model predictions with both steady-state and transient experimental data indicates good agreement.

Several interesting results have been obtained from the model. The response of sulfur retention to a change in a Ca/S ratio shows a strong dependence on the magnitude and direction of change. However the response is essentially independent of whether the change is made in the calcium feed rate or the sulfur feed rate.

Four candidate approaches to control bed retention were identified and evaluated. The first was to change the size distribution of the absorbent feed to the bed. Because smaller particles have higher reactivity, the amount of sulfur absorbed by the bed can be controlled by changing the size distribution of the bed. However, because of the large amount of mass within the bed, the size distribution of the bed changes very slowly. Consequently, the response with this method of control is too slow to be practical. Moreover, reducing the size distribution of the feed could cause additional elutriation which would limit the maximum excursion that could be handled by this method of control. This type of control would also not be able to take advantage of downward excursions in coal sulfur content. This method of control, thus, had several disadvantages and no clear advantage.

The second method of control studied was to adjust the reactivity of the absorbent fed to the bed. This method would also have a slow response due to the large bed inventory. In addition, if a highly reactive dolomite were being used to achieve low steady state Ca/S ratio, there would be little control margin to accommodate transient excursions. Moreover, this system could not take advantage of downward excursions of coal sulfur content. Because of these shortcomings this method of control is not recommended.

The third method investigated considered blending low sulfur fuel with the coal feed in order to maintain a constant rate of sulfur feed to the bed. This system will insure nearly constant percent sulfur retention if the reactivity of the dolomite remains constant. In addition, this system also minimizes the excess dolomite feed required. There are no technical barriers to implementing this control system; however, it is prohibitively expensive when compared to a system that employs a sufficient excess of dolomite feed to insure emission limits are met.

The fourth method investigated is the preferred method. This method maintained the dolomite feed rate in proportion to the rate of sulfur entering the bed. By exercising the model it has been found that retention could be controlled within very small limits by this method. This system also has the ability to accommodate variations in the reactivity of dolomite particles. This is done by adjusting the ratio of dolomite feed to sulfur feed in response to long-term changes in retention. This system reduces excess dolomite usage to a minimum and shows a significant potential cost savings compared to a system using a constant excess dolomite feed to insure compliance with emission limits. One possible disadvantage of this system is that elutriated fines may increase due to increased dolomite feed. While available data does not indicate that this will be a significant disadvantage, further study is recommended.

Because determining retention requires measurement of the sulfur content of the coal feed to the bed, a review was conducted of on-line measurement techniques. From this review it was found that although many techniques are available, the one that appears most suitable is prompt neutron activation analysis of the coal feed. This measurement technique is still undergoing development. The added cost of this device was included in the economic analysis of the constant Ca/S control method and the blending control method. It was not included in the system using a constant excess dolomite feed.

Both of the methods identified for maintaining constant percentage sulfur capture are applicable for use with AFB combustors without fines recycle, and may be applicable to AFB systems that incorporate fines recycle. However, recycle of fines is not incorporated in the model and, therefore, no specific conclusion can be drawn regarding the effects of fines recycle on the results presented in this study.

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SECTION 2

INTRODUCTION

The two objectives of this program are to determine how changes in load and coal sulfur content affect sulfur capture in a pressurized fluidized bed combustor, and to determine methods for controlling bed sulfur absorption properties that minimize sorbent usage. To achieve this objective a computerized mathematical model of a pressurized fluidized bed power plant was developed.

The power plant cycle to be modeled is described in the General Electric Report "Commercial Plant Design Definition" (FE-2357-28), and is illustrated in Figure 1. Some relevant plant data from the report are given in Table I. The plant contains three PFB modules, each composed of two similar fluidized beds (Figure 2). Of all the major plant components, modeling the beds required the most attention to understand sulfur behavior during combustion and how to control and limit its release.

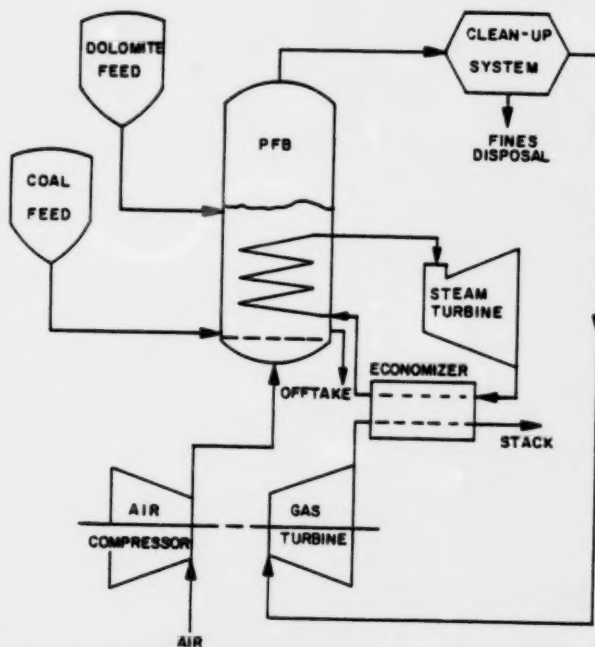


Figure 1. Plant schematic.

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TABLE 1. REFERENCE PLANT DATA

Steam Conditions	24.2 MN/m ² /811 K/811 K (3500 psig/1000°F/1000°F)
Steam Turbine Output	493 MW
Gas Turbine Firing Temperature	1227 K (1750°F)
Gas Turbine Pressure Ratio	10
Gas Turbine Output	153 MW
Parasitic Power	20 MW
Number of PFB Modules	3
Area of Beds	178 m ² (1921 ft ²)
Nominal Bed Height	2.74 m (9 ft)
Coal Feed Rate	61.7 kg/s (489,900 lb/hr)
Dolomite Feed Rate	20.8 kg/s (164,800 lb/hr)
Air Inlet Flow Rate	613.0 kg/s (4,867,000 lb/hr)
Solids Offtake Rate	10.4 kg/s (82,539 lb/hr)
Plant Efficiency	40.6%

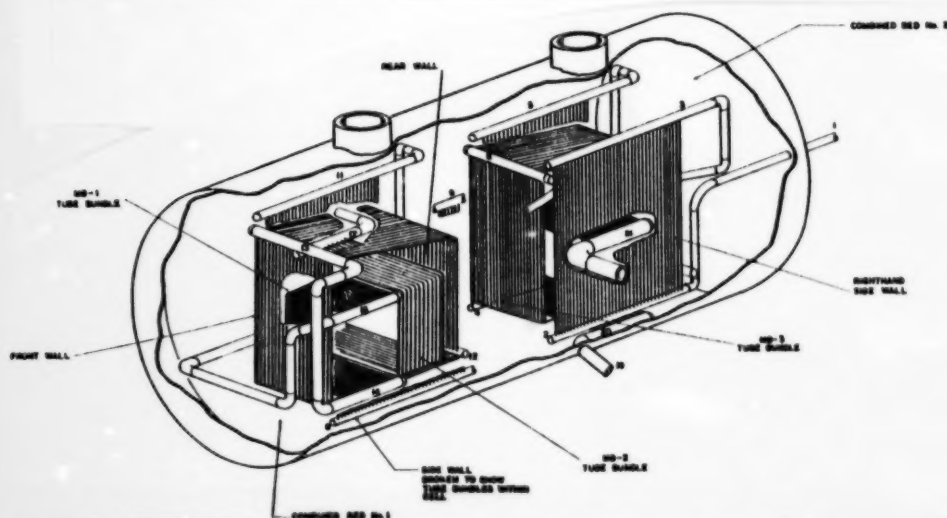


Figure 2. Pressurized fluidized bed combustor.
(Taken from GE report FE-2357-28.)

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All six fluidized beds are similar in fluidizing velocity, heat release, temperature, and solids feed and offtake. Coal is injected at the bottom of each bed. For the purposes of this study it was assumed that the steam tubes were uniformly placed throughout the bed. Moreover, since the beds are similar and are operated simultaneously, it was necessary to model only a single bed from which the performance of all six could be determined. The following section discusses the method used to develop the bed model and explains how each of the major bed processes are accounted for in the model.

The development of the model for this power plant was based on previous computerized analysis performed by General Electric. Although the model includes representations for all the major components, the phenomenological modeling of the sulfur capture process has been emphasized.

Verification of the accuracy of the sulfur capture predictions was determined by comparing model predictions to experimental results from a PFB pilot plant. Excellent agreement was obtained. The model was subsequently used to study the response of the bed to transients in coal sulfur content and dolomite feed in addition to evaluating the candidate control systems.

Besides the modeling work in this program, various methods for measuring coal sulfur content were evaluated and an economic analysis was performed on the most attractive control systems to determine their cost effectiveness. Recommendations for further work are included in this report.

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SECTION 3

THEORY

3.1 FORMULATION OF THE MATHEMATICAL MODEL

This section explains the theory and assumptions used in the model. The programming techniques used in creating the simulation routines that apply these principles are discussed in Appendix B. Information on the flow logic and variable names in the program is also included there.

The desired relationship for sulfur capture in the bed is developed in subsection 3.3, Combustion Chemistry. This is the basic relationship desired for evaluating sulfur capture and methods of controlling bed sulfur absorption properties. As will be shown, the rate of sulfur capture is a function of the reactivity of the dolomite particles in the bed which in turn is related to the bed inventory, i.e., the size and utilization of the dolomite particles. Therefore, following subsection 3.3 the relationships are developed which define these characteristics of the bed. Further, the sulfur capture rate is affected by the bed temperature, so it is necessary to develop the energy balance relations for the bed which in turn define the bed temperature. The bed temperature is also related to the overall power plant operation for which relationships are developed in the last part of this section. The overall power plant simulation also provides other parameters, such as coal feed rate, necessary to complete the inputs to the sulfur capture relationship.

Process Time Scales

In developing the mathematical model it was necessary to understand and account for the time scales of the primary processes. This information was used in determining the extent to which each process was modeled. If a process is completed in a short time compared to other important processes, it can be assumed to occur instantaneously with little loss of accuracy. The problem then becomes more easily solved and generally requires less computation time.

Typical times of the important processes occurring during design point operation in a PFB of the type shown in Figure 2 are given in Table 2. Simplifications to the mathematical model are justified with the comparison of these process times.

In meeting the objective of controlling SO₂ emissions, one of the most important times in Table 2 is the reasonable response time of the sulfur control system. A value of three minutes was chosen because it represents the lower estimate of the response time of the sulfur monitoring and control system. The time required to appreciably change emissions will be longer. Many

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TABLE 2. PROCESS TIMES OF IMPORTANT PROCESSES

Coal Particle Devolatilization and Combustion of Volatile Products	2-10 Sec
Combustion of Char Particles	35-150 Sec
Time for Particles Injected into the Bed to Become Mixed	15-30 Sec
Residence Time for Absorbant	2-8 Hours
Gas Residence Time	2 Sec
Frequency of Variations in Coal Sulfur Content	Seconds-Days
Response of Sulfur Control System	180 Sec
Calculation of Fresh Sorbent	2-15 Min

processes occur on a much shorter time scale: mixing time, gas residence time, and coal devolatilization and combustion. Since all occur much faster than the control system response, these can be assumed to occur instantaneously. Algebraic equations independent of time may therefore be used to model these processes.

On the other hand, processes that occur on the same time scale as the control system response time must be included in the model as a differential equation in the time variable, or algebraic expressions that include time as an independent variable. Examples of processes that are included in the model as algebraic expressions in time are calcination, and feed coal sulfur content. Examples of processes that are included in the model as differential equations in time are the bed inventory and bed temperature.

Simplification of the modeling process using the arguments discussed above limits the frequency of the transient sulfur emissions that can be studied using this model. Consequently, response of the plant to short duration transients (<60 sec) in sulfur emissions can only be considered to be an approximation. However, it is not expected that such short term emissions would be a major contributor to total cumulative plant sulfur discharge. In any case, these high frequency variations in sulfur emissions are not within the scope of this study.

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Discussion of Combustor Processes

With an understanding of the time constants involved in fluidized bed combustion, each process must be understood and modeled as appropriate. Each portion of the model will be discussed in the following sections starting with bed dynamics and combustor chemistry (sulfur release and capture), then bed inventory, heat transfer, energy balance, and the combined cycle plant and power generation controls.

3.2 BED DYNAMICS

An understanding of the bed dynamics of the combustor are a prerequisite to understanding the retention of sulfur.

Bed Expansion

Expressions for minimum fluidization velocity, U_{mf} , and the expanded bed height, H_t are (Babu, Shan and Talwalker, 1978)

$$U_{mf} = \frac{\mu}{\rho_g} \left[((25.25)^2 + .0651 Ar)^{.5} - 25.25 \right] \quad (3.1)$$

$$\frac{H_t}{H_{t_{mf}}} = \frac{1 + 10.978(U_{sg} - U_{mf})^{0.738} \rho_s^{1.006} \rho_g^{0.376}}{U_{mf}^{0.937} \rho_g^{0.126}} \quad (3.2)$$

These equations were obtained by fitting available data from experiments using dolomite, limestone, char, and coal. The equation for U_{mf} resembles the Ergun equation in form but has slightly different coefficients.

Gas Backmixing and Phase Interchange

Gas phase backmixing occurs when the gas velocity in the emulsion phase goes downward. This occurs when the ratio, U_{sg}/U_{mf} is larger than 5. For operating conditions in the PFB, this ratio will be well below this value, and therefore not of concern in this study.

Exchange of gas between the bubble and emulsion phase is difficult to evaluate numerically due to the large number of internal structures within the bed. However, such exchange is expected to be rapid because it is known that these structures enhance interchange of gas between the bubble and the emulsion phases. For this reason an infinite rate of exchange between the two phases will be assumed.

The absence of gas phase backmixing and the infinite rate of interphase transfer, justifies the use of a homogeneous bed and a single gas phase velocity, U_e . This results in a considerable simplification of the expressions for sulfur capture.

Solids Mixing

Solids mixing is important in determining the location of volatile product evolution and consequently the distribution of SO_2 generation. As a first approximation, this model assumes that solids mixing is fast compared to the time required for devolatilization of coal particles. In reality these two processes occur on nearly the same time scale as discussed in Section 4, "Model Validation." For dolomite, however, the feed, offtake and utilization occur much more slowly than bed mixing, so the bed population can be assumed to be homogeneous.

3.3 COMBUSTOR CHEMISTRY

The chemical reaction in a pressurized fluidized bed are extremely complex. This portion of the report discusses the representation used in this simulation and related simplifying assumptions.

Sulfur Release

The process of sulfur generation within the bed depends on devolatilization and combustion of the volatile products in addition to the combustion of char. Over half of the sulfur in coal is typically given off during devolatilization (Lowry, 1940). The remainder of the sulfur release is commonly assumed to be proportional to char combustion. Although the latter process is much slower than the first, both can be considered fast with respect to the response of the sulfur control system. For this reason, the instantaneous sulfur capture can be determined using algebraic equations.

The location of sulfur generation within the bed is necessary to determine the retention of sulfur dioxide. This generation distribution is difficult to predict due to uncertainties in the rate of SO_2 generation during devolatilization and combustion. The sulfur dioxide generation distribution can be approximated by the following exponential equation:

$$G(z) = \frac{W_c f_{sae} e^{-\frac{az}{H_t}}}{M_s A_s H_t (1 - e^{-a})} \quad (3.3)$$

The value of a is a measure of excess air and is the only independent variable in the expression. If SO_2 generation is proportional to combustion which is limited by the partial pressure of oxygen, equation 3.3 is an exact representation (Horio and Wen, 1978) when

$$a = \ln \left[\frac{1 + \text{excess air ratio}}{\text{excess air ratio}} \right] \quad (3.4)$$

In reality the SO_2 generation will be lower in the bed than predicted by the above expression, because the release will be not only limited by local oxygen concentration, but also by interactions between bed mixing and volatile

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product release. Since the time required for mixing and devolatilization are relatively close, release and combustion of volatile products, which constitutes most of the SO₂ generation, can be expected deeper in the bed than the expression for "a" would predict. The sensitivity of the model to location of sulfur release is discussed in Section 4 on the model validation.

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Sulfur Capture

The absorption of SO₂ in the combustor is determined by the fluid dynamics of the bed and the reactivity of the dolomite in the bed. In fluidized beds operating at superficial velocities greater than that of minimum fluidization, a bubble phase and an emulsion phase are formed. SO₂ sorption occurs primarily in the emulsion phase, whereas the bubble phase bypasses this process and decreases the sulfur retention. The amount of gas exchanged between the phases controls the extent to which this is true. As previously discussed, the bed is assumed to have infinitely large interphase gas transfer because of the internal structures of the bed. Consequently, the combustor can be modeled as a single phase homogeneous bed and the SO₂ sorption governing equation becomes:

$$U_e \frac{d[SO_2]}{dz} = -k_1[SO_2] + G(z) \quad (3.5)$$

where k_1 is the absorption rate constant (see next section) for the entire bed, $[SO_2]$ is the concentration of sulfur dioxide, z is the vertical location in the bed, and U_e is the effective gas velocity through the interstices of the bed. In other words:

Change in Local Sulfur Flux = (Local Rate of Sulfur Absorption)
+ (Local Rate of Sulfur Generation)

Equation 3.5 is solved to determine the mass flux of sulfur leaving the bed:

$$R_o = U_{sg} A_b C_2 e^{-a} - e^{-k_2 H_t / U_e} \quad (3.6)$$

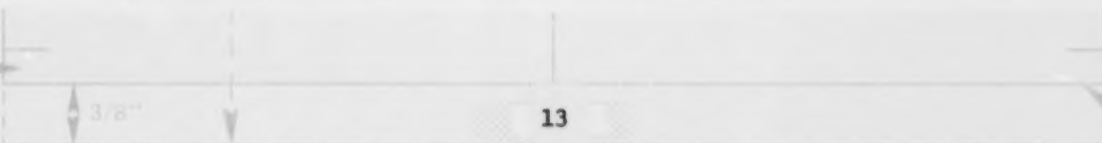
where

$$C_2 = \frac{k_2 / k_1}{1 - (a U_e / k_1 H_t)} \quad (3.7)$$

$$k_2 = \frac{W_c f_s a}{M_s A_b H_t (1 - e^{-a})} \quad (3.8)$$

These algebraic equations govern sulfur release and capture in the bed.

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Figure 3 is a profile of the sulfur dioxide concentration as a function of distance above the distributor. Near the bottom of the bed, the concentration increases sharply due to the large amount of combustion occurring there. Higher in the bed, the concentration decreases due to the decreased rate of combustion and exposure to larger amounts of dolomite.

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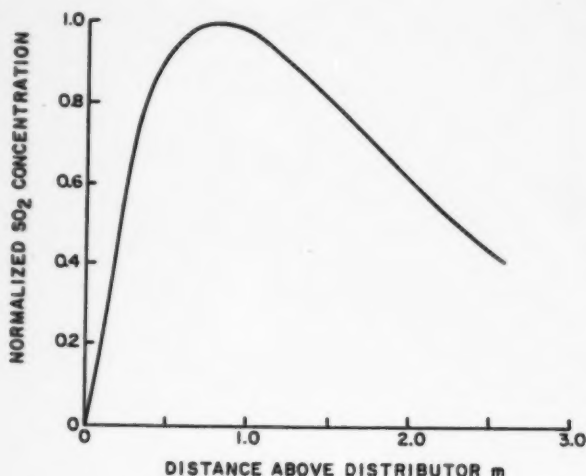


Figure 3. Normalized SO₂ concentration as a function of height.

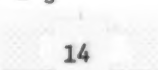
Absorption Rate Constant

To determine the sulfur retention, it is necessary to calculate the reaction rate constant which is a function of such variables as temperature, type of absorbent, calcination atmosphere, particle size, and utilization. There have been many attempts to determine functional relations for the reactivity rate (references by: O'Neill, Keairns and Kittle, 1976; Chrostowski and Georgakins, 1978; Hartman and Coughlin, 1975; Siegal et al., 1978; Borgwardt, 1970; Newby et al., 1978). This simulation is based on the TGA rate data reported by Westinghouse (reference by Newby et al.) for 1337 dolomite calcined and sulfated under conditions comparable to those in a PFB combustor.

The Westinghouse TGA (Thermogravimetric Analysis) rate data, which were reported as a function of size and utilization, were included in the model after fitting with cubic functions. One polynomial was included for each of the four sizes reported. This information was integrated over the entire bed population distribution to determine the instantaneous reaction rate constant for the bed (k_1). Expressing the integration as a sum over the entire bed population, the rate constant is:

$$k_1 = \sum_i \sum_j \frac{k_{ij} n_{ij}}{V} f_j \quad (3.9)$$

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where

i = sizes of dolomite particles

j = utilization ranges used in the finite difference approach

k_{ij} = reactivity of particles of a given size and utilization

n_{ij} = moles of particles of a given size and utilization

V = expanded volume of the bed minus the volume of the inerts

f_j = polynomial that accounts for temperature dependence
of the rate constant

The polynomials, f_j , account for the temperature dependence of the reaction rate constants and were also obtained from the Westinghouse TGA data. The value of f_j is 1.0 at 1227 K and decreases as the temperature decreases.

3.4 BED INVENTORY MODEL

In order to determine the rate of absorption of SO_2 within the bed, the population distribution of dolomite by size and utilization must be known. The population with the bed at equilibrium conditions for a Ca/S ratio of 1.48 is shown in Figure 4. This distribution will change during transients, causing the reactivity of the bed for SO_2 capture to change. Consequently, determination of the bed population distribution as a function of time is a very important part of the model.

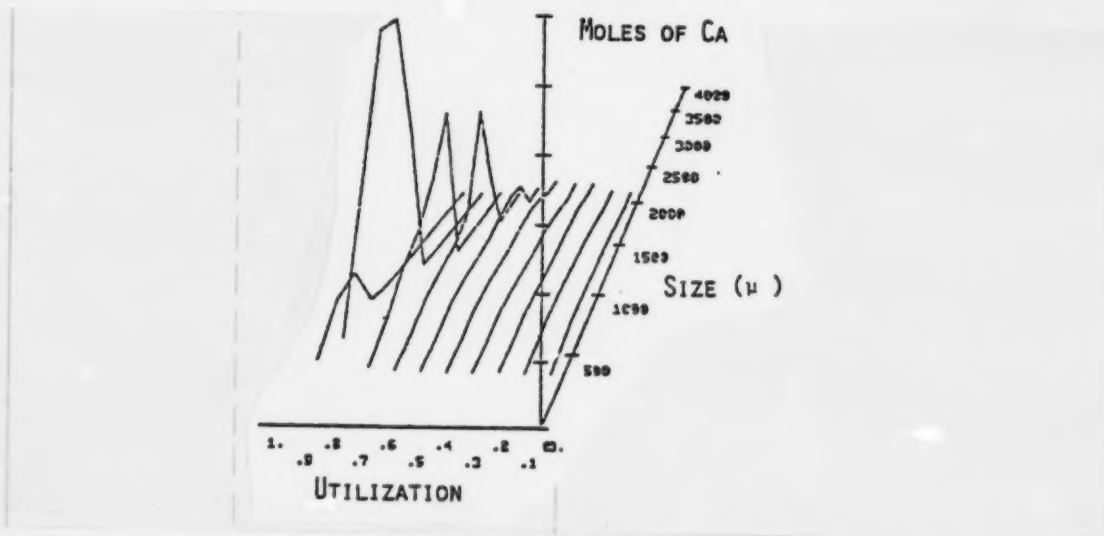


Figure 4. Molar population distribution as determined in the simulation as a function of size and utilization for a Ca/S ratio of 1.48,

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Governing Equation

The differential equation which governs the distribution of particles of dolomite is derived by noting that the distribution of calcium within the bed, N , is a function of time, t , particle size, x , and utilization, u . The equation then has the form (Hurlbert and Kate, 1964):

$$\frac{dN}{dt} = \frac{\partial N}{\partial t} + \frac{\partial}{\partial x} \left(N \frac{dx}{dt} \right) + \frac{\partial}{\partial u} \left(N \frac{du}{dt} \right) \quad (3.10)$$

The moles of calcium of a particular size and utilization are defined as:

$$n_{x,u} = N_{x,u} \Delta x \Delta u \quad (3.11)$$

The computer simulation is written in terms of the mass of particles of a particular size and utilization:

$$b_{x,u} = n_{x,u} M \quad (3.12)$$

where the constant M is the molecular weight of dolomite.

The first term on the right-hand side of Equation 3.10 is the change in the bed inventory with time while keeping the size and utilization constant:

$$\left. \frac{\partial N}{\partial t} \right|_{xu} = \text{Feed Rate (F)} - \text{Offtake Rate (O)} \quad (3.13)$$

- Elutriation (E) + New Particles (Fines)
Created by Attrition (A)

Each of the mass flow rates is calculated as follows:

F = Feed Rate = Flow of fresh dolomite with a lag proportional to the square of the particle radius to represent calcination

O = Offtake Rate = Flow of sorbent leaving the bed in order to maintain bed height as calculated by the control system

E = Elutriation = Particles blown out of the bed with the hot gas (Merrick and Highley, 1973)

$$E = J * .00012 + 130. * \exp \left[-10.4 \left(\frac{U_t}{U_{sg}} \right)^{.5} \left(\frac{U_{mf}}{U_{sg} - U_{mf}} \right)^{.25} \right] \quad (3.14)$$

where

J = Gas flow through the bed (kg/s)

U_{sg} = Superficial gas velocity (m/s)

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U_{mf} = Minimum fluidizing velocity (m/s)

U_t = Terminal velocity (m/s) is given by Kuni and Lavenspiel (1969)

$$U_t = x \left(\frac{4}{225} \frac{\rho_s^2 g^2}{\rho_g \mu} \right)^{.333} \quad 0.4 < R_e < 500 \quad (3.15)$$

$$U_t = \left(3.1 \frac{\rho_s g x}{\rho_g} \right)^{.5} \quad 500 < R_e < 2 \times 10^5 \quad (3.16)$$

A = Attrition = The small particles produced by wearing away pieces of the larger particles. The value of A represents the generation of fines by attrition. As shown in Appendix A, most of these fines are quickly elutriated. In this study it was assumed that the large majority of the particles were immediately elutriated. The remaining small percentage (1.9%) of particles are divided equally among the sizes below 700 μ m, and appear as a source term, A, for those sizes.

The second term on the right side of Equation 3.10 is the change in bed population caused by changes in particle size times the rate of change of size, in other words this term describes attrition. The rate of attrition is:

$$\frac{dx}{dt} = \frac{-k_a f_d (U_{sg} - U_{mf})}{3} \quad (3.17)$$

where:

k_a = constant which was determined by fitting experimentally data (Roberts et al., 1977)

f_d = fraction of particles in the bed smaller than the given size.

The final term on the right side of Equation 3.10 describes the effect of changing particle utilization on bed population distribution. The rate of utilization is:

$$\frac{du}{dt} = \frac{k_{i,j} (R_o - R_i)}{k_1 V} \quad (3.18)$$

where:

R_o = rate of sulfur leaving the bed, moles/s

R_i = rate of sulfur entering the bed, moles/s

V = volume of the bed, m^3

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$k_{1,j}$ = absorption rate constant, which is dependent on particle size, x , and utilization, u .

k_1 = absorption rate constant for the entire bed

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In this simulation, the governing Equation 3.10 is represented with finite differencing by size and utilization. The total size distribution is divided into 11 smaller ranges, each of which is represented by the median value. Likewise, the utilization is divided into 10 smaller segments each representing 10% and represented by the average, i.e., 5% represents the 0-10% utilization, etc. In this way, the rate constants and all the calculations are determined for a portion of the bed with a limited size and utilization range.

This approach requires one to assume that the particle distribution is uniform throughout the bed. Since, as noted in TABLE 2, calcination takes 3-5 minutes and only 15-30 seconds are required for the injected particles to become mixed uniformly throughout the bed, it may be assumed that samples taken from any two points in the bed will have the same distribution of particles with respect to utilization. It is thus reasonable to assume a uniform size distribution throughout the bed, because the gas velocity at operating conditions is considerably higher than that required for fluidization of even the largest particles within the bed.

With this description of the population distribution within the bed, it is possible to determine the characteristics of the bed population distribution and ultimately the sulfur retention. The next step in this process is to determine the energy balance within the combustor as the temperature has a major impact on sulfur retention.

3.5 ENERGY BALANCE

This subsection describes the processes important in solving the energy conservation equation for the combustor. A discussion of heat transfer to the steam tubes is followed by discussions of the rate and energy required by the calcination reaction and, lastly, the solution of the energy conservation equation for the bed.

Heat Transferred to the Steam

Heat transfer to the steam tubes in a fluidized bed is a complex problem. Literature discussing heat transfer coefficients is in considerable disagreement. It has been found that these coefficients depend on pressure, fluidizing velocity, particle size, and bed temperature. Although at present it is quite difficult to predict accurately the value of this coefficient for the system being studied, the required value of the product of the heat transfer coefficient and steam tube surface area (hA) has been determined for design conditions. The model has been formulated to use this product, adjusted by a factor to account for off-design conditions. The following identifies the considerations in choosing the adjustment factor.

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The model has been prepared assuming only small perturbations from the design point. Large excursions such as plant start-up and shutdown are beyond the scope of this study. The expanded bed height remains approximately the same, i.e., all the steam generator tubes in the bed remain covered keeping the area of heat transfer constant. Steam generation and the plant performance would be substantially affected if steam tubes were uncovered.

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A typical curve of the coefficient of heat transfer, h , as a function of the superficial gas velocity is shown in Figure 5. As the velocity of the gas increases above the minimum fluidization velocity, h increases rapidly to a large value, and remains relatively constant. All of the conditions that are within the scope of this study are also in the range where h has little dependence on gas velocity. Therefore, with a constant area A and nearly constant h , we are reasonable in assuming a constant hA .

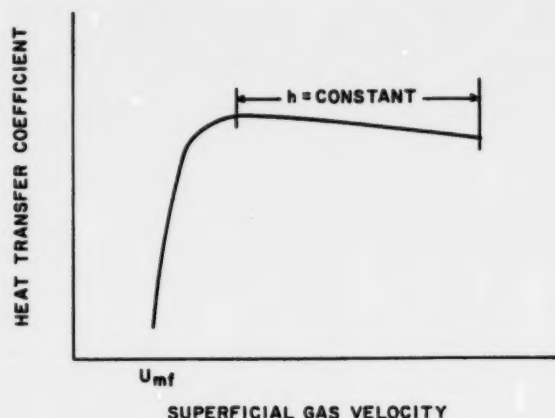


Figure 5. Dependence of heat transfer coefficient on superficial gas velocity.

Quantitative data of the effects of U_{sg} on h are shown in Figures 6 and 7 as reported by Canada and McLaughlin (1978). These figures show the results of a study performed at GE to determine the change in heat transfer coefficient for glass spheres as a function of fluidizing velocity and pressure. The abscissa has been nondimensionalized by the terminal velocity, U_t . It should also be noted that U_{mf}/U_t in Figure 6, is approximately 0.10 and in Figure 7 it is approximately 0.08.

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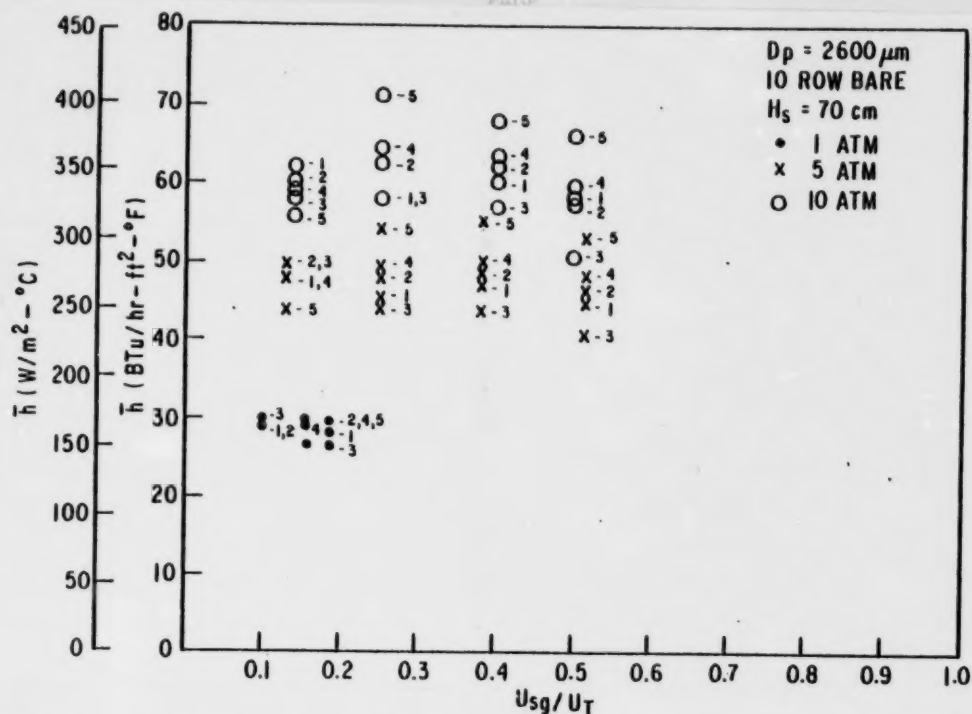


Figure 6. Experimental data (reported by Canada and McLaughlin) of the heat transfer coefficient as a function of the U_{sg}/U_t ratio for glass spheres. Numbers indicate experimental runs. ($U_{mf}/U_t \approx 0.1$)

Comparison of Figures 6 and 7 also show the dependence of heat transfer coefficients as a function of size. Most of the dolomite particles within the bed are between the sizes of glass spheres used to obtain the data shown in these figures. The average diameter of dolomite particles on a weight basis is about 1050 microns. The effect of size on heat transfer is neglected, since the size distribution of particles within the bed will not change enough to significantly affect the heat transfer coefficient.

The final variable affecting the heat transfer coefficient is temperature. The dependence of h is approximately linear with temperature because of the limited range of interest in this study. The slope of this linear approximation was determined by fitting data for quartz sand with an average diameter of 0.34 mm (Davidson and Harrison, 1971):

$$k_h = 1. + .5 \frac{(T - 1227)}{1227} \quad (3.19)$$

This factor, k_h , is the multiplier of the heat transfer coefficient 1227 K and is used to account for the temperature dependence of hA in the simulation.

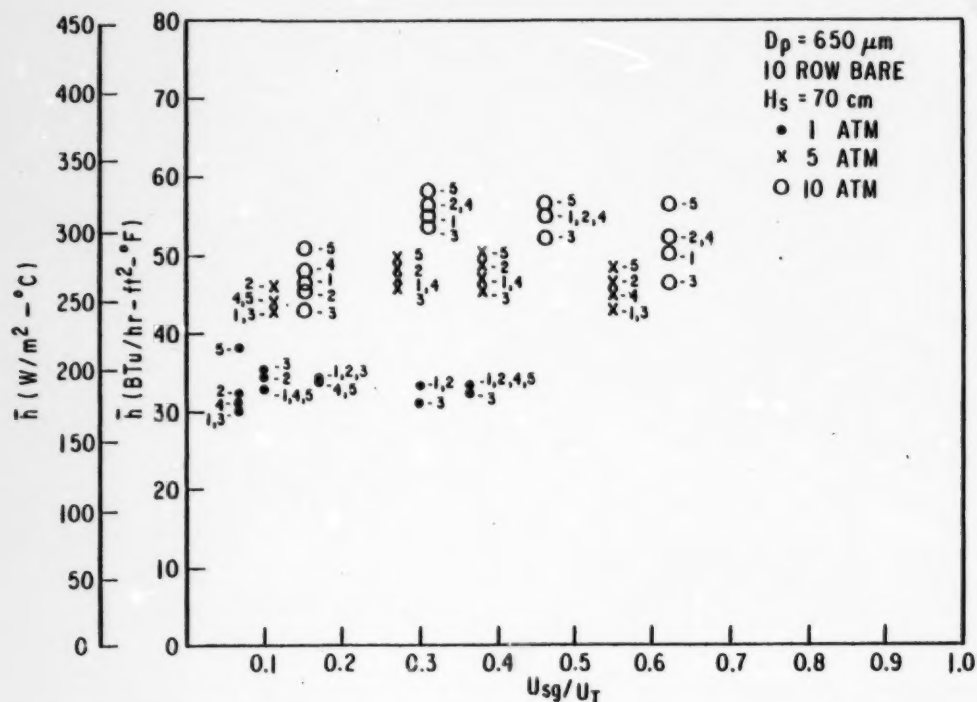


Figure 7. Experimental data (reported by Canada and McLaughlin) of the heat transfer coefficient as a function of the U_{sg}/U_t ratio for glass spheres. Numbers indicate experimental runs. ($U_{mf}/U_t \approx 0.08$)

Calcination

Calcination represents a small energy sink term which affects bed temperature and power generation. Although the process of calcination is known to occur very rapidly, there is little information which describes the exact rate of calcination or factors which affect its value. The accurate prediction of time required to calcine dolomite is not crucial to this study because it is known to be much faster than changes can be made to the average utilization of the bed.

The time required for calcination of a particle of dolomite has been estimated with the following approximations:

- constant specific heat of dolomite
- constant coefficient of heat transfer
- particle temperature remains constant during both half and full calcination processes
- rate of calcination is limited by heat transfer, not chemical reactions

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With these assumptions and noting that the criteria for lumped heat capacity analysis is satisfied for dolomite particles in the bed, the time required for calcination can be determined. The properties used to calculate calcination time requirements are in Table 3. For particles of dolomite used in a PFB, the time to reach the temperature (1050°F) required for the initiation of half calcination is:

$$t_{0-1/2} = 450 r^2 \quad (3.20)$$

where time is measured in seconds and r is the particle radius in cm. The process of half calcination is completed in time (seconds):

$$t_{1/2} = 4490 r^2 \quad (3.21)$$

Similar expressions can be derived for the time required to reach the temperature (1680°F) of full calcination and the time to complete calcination, which if added, produce an expression for the time to reach full calcination:

$$t_{cal} = 5580 r^2 \quad (3.22)$$

The simulation uses Equation 3.22 to determine the time required for calcination before a particle can actively absorb sulfur. Prior to reaching full calcination, the dolomite may absorb a small amount of SO_2 (approximately 5% utilization).

TABLE 3. CONSTANTS FOR CALCULATING CALCINATION TIME

Nusselt Number	2
Thermal Conductivity	0.012 W/cm K
Specific Heat	40 cal/mole K
Density	1.41 g/cm ²
Heat of Reaction	
Half Calcination	125 kcal/mole
Full Calcination	138 kcal/mole

The above information was used to determine the rate of energy absorbed by the calcination reaction and was included in determining the net rate of chemical energy release.

Energy Balance Equation

In order to calculate the energy balance for the combustor, it is necessary to determine the energy available from the chemical reactions. The higher heating value is used to calculate the amount of free hydrogen

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$$W_{FH} = (HHV - H_{fC} W_C - H_{fS} W_S) / H_{fH} \quad (3.23)$$

where H_f is the heat of formation, HHV is the higher heating value, and W_C and W_S are the masses of carbon and sulfur, respectively, in the coal feed. It is necessary to calculate the amount of free hydrogen because the coal analysis does not specify the hydrogen available to react. The total gas produced by combustion is determined from the amount of CO_2 , SO_2 , H_2O , and N_2 that can be created assuming total combustion. This assumption is valid because there is about twenty percent excess air. With this information the energy flux due to the mass flux of gases can be calculated.

The energy balance around the bed can be written:

$$\begin{aligned} \text{Energy Available for Steam} = & (1 - \text{fraction of losses}) \\ & [(\text{Energy Change Due to Chemical Reactions}) + \\ & (\text{Change of Thermal Energy Stored in Bed})] \\ & + (\text{Energy Flux Due to Mass Flows}) \end{aligned}$$

or in equation form:

$$\begin{aligned} \dot{Q}_s = & (1 - \eta_L) \left[\Delta \dot{H}_R - \dot{M}_b C_p \frac{(T_{t+\Delta t} - T_t)}{\Delta t} \right] \\ & + \sum (H_{in,i} \dot{m}_{in,i} - H_{out,j} \dot{m}_{out,j}) \end{aligned} \quad (3.24)$$

where i and j indicate the individual flows (e.g., dolomite, air, ash, etc). The heat of reaction, ΔH_R , is a combination of combustion, calcination and surface retention. The rate of energy transferred to the steam tubes can also be written

$$\dot{Q}_s = k_h h A \Delta T_{lm} \quad (3.25)$$

where the calculation of k_h , h and A have been previously discussed and ΔT_{lm} is the log mean temperature difference calculated at the bed temperature and the inlet and exit steam temperatures. These two expressions for $\dot{Q}_s$ are solved iteratively to determine the actual bed temperature which produces the energy balance.

It is assumed that the temperature and pressure of the steam entering and leaving the steam generator are constant for all plant operating conditions within the scope of this study; that is, changes in bed temperature are reflected only in the amount of steam produced.

3.6 OVERALL POWER PLANT SIMULATION

The purpose of the simulation is to evaluate potential SO_2 emission control methods. The primary concern, therefore, was to develop a plant model with sufficient accuracy to adequately evaluate the relative performance of various potential SO_2 emission control methods. To meet this objective, the

bed model is most important and the steam turbine, gas turbine and air compressor models are less significant. Accordingly, these latter representations have been simplified by assuming constant efficiencies and constant speeds. Further, the time constant for the entire steam turbine is very close to the calculation interval of the program. Therefore, for purposes of evaluating relative emission control methods, the steam turbine appears to have virtually instantaneous response. Thus it is represented with a steady-state equation (power of steam turbine = flow of steam * Δ enthalpy * units conversion) following a time lag (numerical integration) representing delays in changes in steam conditions due to the volume of steam within the piping and manifolding.

The gas turbine model uses a double loop iteration to solve for bed pressure, turbine nozzle pressure and turbine inlet flow. This method simultaneously solves the equations representing: (1) the pressure in the freeboard space above the bed and (2) in the clean-up system, (3) in the turbine inlet header and manifold and (4) the flow into the turbine.

$$P_{Ti} = \frac{W_{Ti} \sqrt{T_{Ti}}}{C_1} \quad (3.26)$$

$$\Delta P_{FB} = c_2 (W_{PFB} - W_{Ti}) R T_{BED} / M_g \quad (3.27)$$

$$P'_{FB} = P_{FB} + \Delta P_{FB} \quad (3.28)$$

$$W_{Ti} = c_3 \sqrt{P'_{FB} - P_{Ti}} \quad (3.29)$$

where P_{Ti} and P_{FB} are the turbine inlet and fluidized bed pressures, T_{Ti} and T_{BED} are the turbine inlet and bed temperatures, W_{Ti} and W_{PFB} are the gas flows into the turbine and leaving the combustor, P'_{FB} represents the updated fluidized bed pressure for the next iteration, ΔP_{FB} represents the error in the calculated value for P_{FB} due to imbalance in the calculated values for fluidized bed flow and turbine inlet flow, c_1 , c_2 , and c_3 are constants, and M_g is the molecular weight of the gas. When the iterative loop is closed, the turbine horsepower and compressor discharge pressure are calculated from the first principles of thermodynamics. Using ambient and compressor discharge conditions, the compressor power requirements are calculated and subtracted from the gas turbine power to produce the net turbine output power.

Power Generation Control

The control system modeled in this simulation (Figure 8) is a simplified system representative of the controls planned for the CFCC power plant. The error in the plant generated load is processed by the Coordinated Boiler-Turbine Control. This control initiates operating parameter changes of the bed, steam turbine and gas turbine. The bed operating condition is changed by adjusting both the bed temperature and the air flow set points. This

causes an error signal that modifies coal flow until the bed temperature reaches the new set point. Bed air flow is changed by scheduling the position of the gas turbine Inlet Guide Vanes (IGV). Fixed schedules as a function of power have been established for both IGV settings and bed temperature.

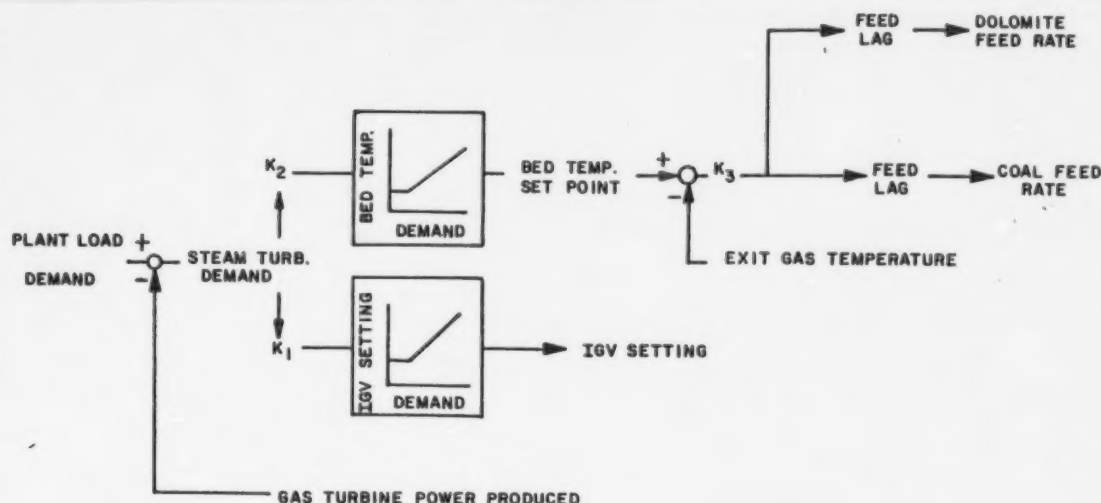


Figure 8. Simplified plant controls.

Although the gas turbine is not controlled directly, its feedback signal impacts plant operating conditions. The steam turbine demand, modified by the gas turbine power generation, is the signal which controls bed temperature and air flow set-points. As the air flow and bed temperature adjust, gas turbine power generation also changes producing a new steam turbine demand. This process continues until the gas and steam turbines eventually reach their normal balance of power generation.



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SECTION 4

MODEL VALIDATION

4.1 SULFUR GENERATION FUNCTION

Qualification of a computer simulation is one of the most important steps in developing a model, because the results are only as good as the accuracy with which valid experimental data can be reproduced. Besides matching the results of experiments at steady state, the model must accurately reproduce the time constants in a transient.

The most difficult portion of the simulation to verify is the sulfur generation function because very little experimental data exists. For this reason it was necessary to evaluate the sensitivity of the sulfur retention to the generation function used. This model has been validated primarily with data from the Exxon Miniplant.

The model for sulfur generation and capture was originally formulated assuming that sulfur dioxide generation within the bed was proportional to carbon combustion. This distribution can be thought of as a pessimistic approximation because it is known that a majority of the sulfur in coal is released as volatile products within about 10 seconds after injection, which then combust rapidly. This would imply that the sulfur is released more deeply in the bed than is predicted by the model. Consequently, this method of modeling the sulfur release is expected to underpredict the actual retention.

Other distributions deeper in the bed have also been investigated. An optimistic prediction of the sulfur release and capture can be obtained by estimating the location of the devolatilizing coal particles and assuming all the sulfur is released during devolatilization. The location of coal particles can be estimated by assuming that devolatilization occurs uniformly for the 10 seconds after the coal particle is injected into the bed. The distribution of these particles can be determined by solving the differential equation governing diffusion (Equation 4.1) with a constant source term as a boundary condition.

$$\frac{\delta C_s}{\delta t} = D_{SA} \frac{\delta^2 C_s}{\delta x^2} \quad (4.1)$$

The value of D_{SA} is not easily obtained since many factors affect its value. Horio and Wen (1978) have determined the value of this constant for the Exxon

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Miniplant by fitting the temperature profile predicted by their model to test data. For cases of interest here this value ranged from 200 cm²/s to 500 cm²/s. The solution of the transient differential equation evaluated at 10 seconds for both values of D_{SA} is shown in Figure 9. Also shown on this figure is an exponential function that approximates the concentration distribution ($a = 6.0$) and the exponential sulfur generation distribution corresponding to the pessimistic prediction ($a = 1.79$). There is a considerable amount of difference between these two exponential distributions.

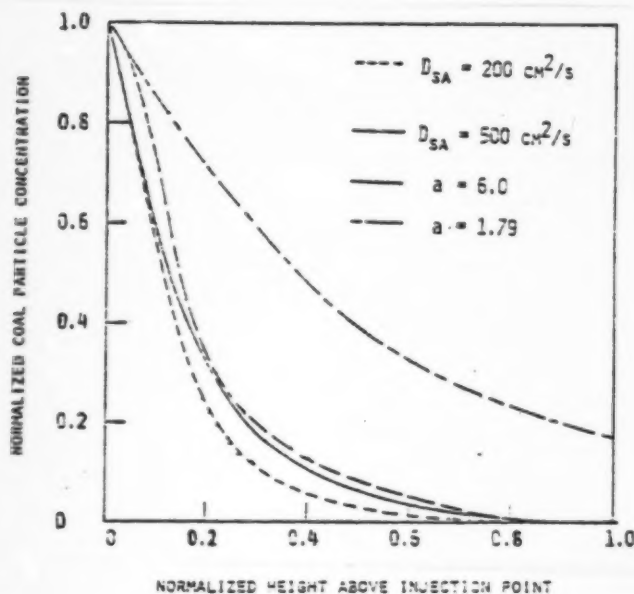


Figure 9. Normalized coal particle concentration versus height above injection point.

The effect of these two sulfur generation patterns was studied by using them in the model. Figure 10 shows the result. Although the sulfur generation pattern is considerably different, the capture predictions do not change significantly.

4.2 STEADY STATE VERIFICATION

Detailed data for three particular runs of the Exxon Miniplant have been selected for detailed qualification of the computer model at steady-state operating conditions. The data corresponds to runs 43.3, 43.4 and 43.5 as reported in Exxon's Third Annual Report (Hoke, 1978).

Figure 11 is a comparison of sulfur retention as predicted by the simulations with experimental results from the Exxon Miniplant. Although the predicted retention correlates well with the data, the results of the model slightly underpredict retention as discussed in the preceding paragraphs on the sensitivity to the sulfur generation function. With the ability to predict steady-state results, attention must now focus on reproducing the data from the transients.

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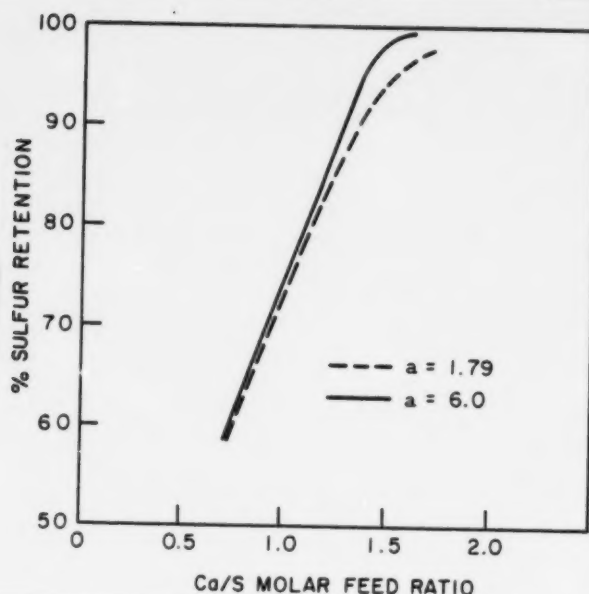


Figure 10. Percent retention versus Ca/S molar feed ratio for an optimistic ($a = 6.0$) and pessimistic ($a = 1.79$) prediction of sulfur release

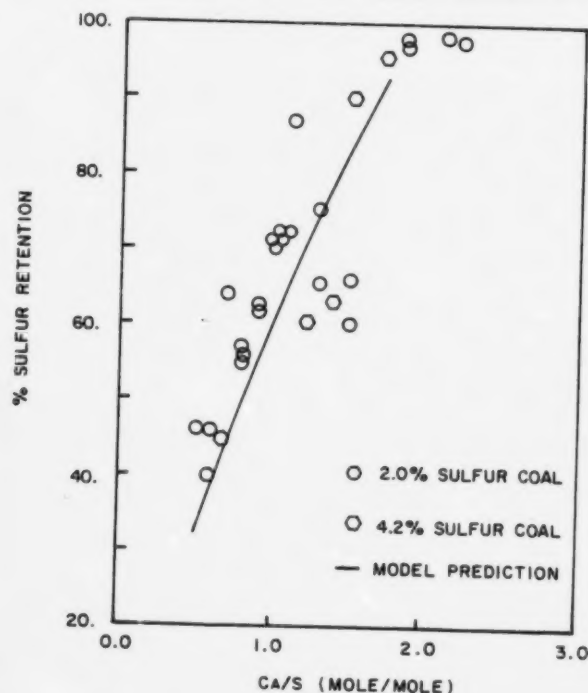


Figure 11. Comparison of model prediction and experimental results for the Exxon Miniplant (Hoke, 1978).

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4.3 TRANSIENT TESTS

In order to support this study, EPA requested Exxon to conduct Runs 99 and 100 on the PFB Miniplant in order to provide transient response information (Hoke, 1980). As we attempted to compare our model to these runs, we encountered difficulties in obtaining reasonable matches. The main reason for this is the inaccuracy of the experimental measurements. As shown in Figure 12, the initial and final points do not match the steady-state data even though the system was believed to be at equilibrium. It is impossible to force the model to agree with these transient data points, because it agrees well with the steady-state data.

Exxon reported its transient results with two calcium-sulfur ratios: one was the ratio as set on the feed mechanism and the second was the value they calculated from the retention and utilization. At equilibrium, the Ca/S ratio is retention divided by utilization. For this reason, the calculated ratio from the measured retention and utilization match steady-state data fairly well prior to the first step change, however, the bed conditions never reached equilibrium, and this calculated ratio is a poor match for steady-state data. With this discrepancy, it was decided that in order to verify the time constants within the simulation, Ca/S ratios should be chosen to produce the desired sulfur retentions. Table 4 shows the various ratios. In obtaining the desired feed ratios, the coal and air feed rates are equivalent to those used in the miniplant tests. Only the feed rate of dolomite was changed.

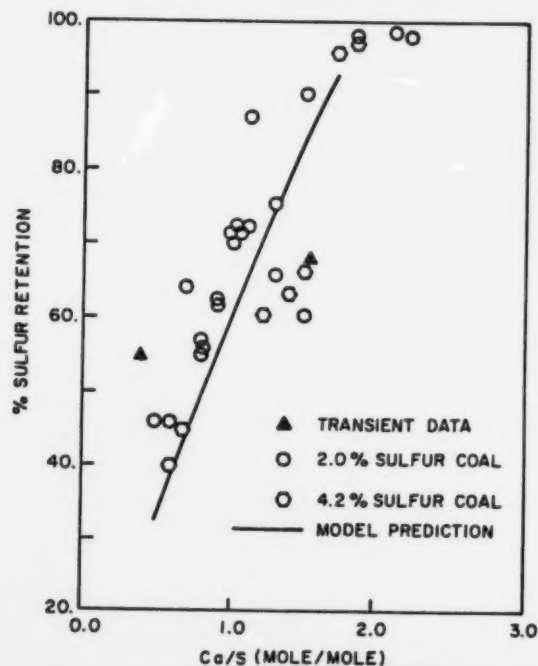


Figure 12. Initial and final values of the transient Exxon data compared to other Exxon data and model prediction (Hoke, 1978).

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TABLE 4. Ca/S FEED RATES FOR TRANSIENT MODEL VALIDATION

Ca/S Ratio		
Set on Feed System	1.25	0.32
Calculated (Ca/S = R/U)	0.90	0.68
Value to Reproduce Retention	1.17	0.90
Hours Used	0-6.0 14.0-24.75	6.0-14.0
Coal Feed Rate (Kg/s)	45.95	50.74
Dolomite Feed Rate (Kg/S)	5.69	4.76
Air Feed Rate (Kg/S)	680.00	680.00

Using these Ca/S feed ratios, the simulation reproduces the miniplant results quite well (Figure 13). Since the slopes of the curves match well, the time constants and rates for various processes used in the simulation have been verified. In evaluating the results of this comparison, it is necessary to be aware of the following:

- The excursions following each step change in Ca/S ratio are due to:
The calcination time in effect changes the coal sulfur instantaneously while delaying any change in available sorbent
The excess air ratio fluctuates causing changes in the location within the bed of combustion (and sulfur release) as specified by the sulfur generation function.
- Approximately 30% of the dolomite used during the Exxon Miniplant transient test was larger than the largest size that can be used in this simulation (limited by the availability of reactivity data). As a result, we attempted to obtain approximately the same average particle size by using a high concentration of larger particles. Decreasing the number of small particles in this way reduces the bed reactivity and ultimately the sulfur retention. The average particle size changes throughout the run from 1531 to 1687 microns because steady state has not been reached.

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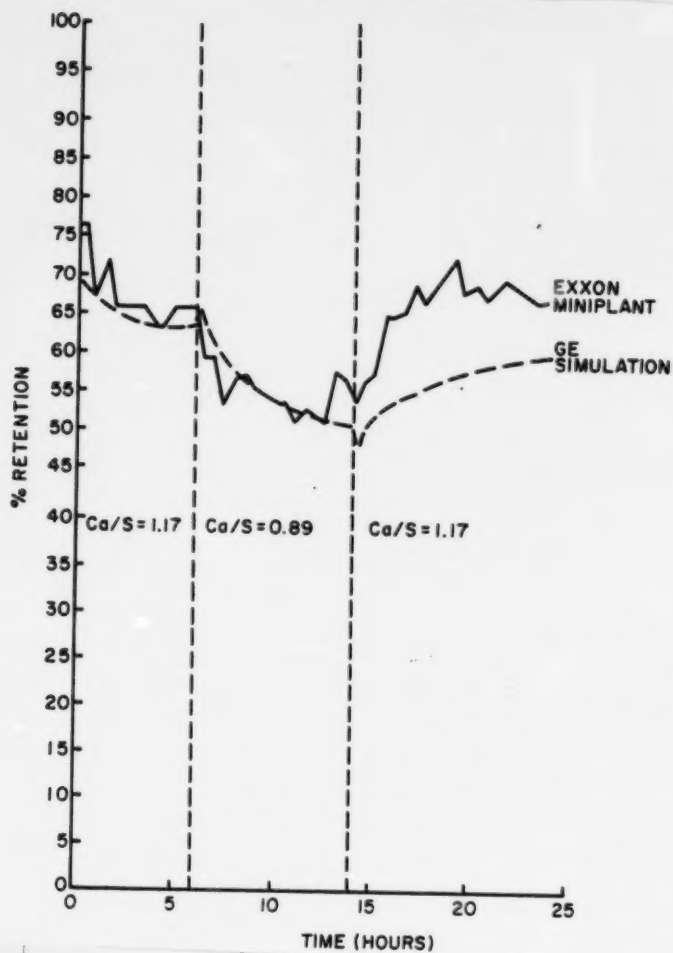


Figure 13. Sulfur retention during transient test.

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SECTION 5

ANALYSIS OF THE TRANSIENT RESPONSE OF THE FLUIDIZED BED COMBUSTOR

5.1 STEP CHANGE IN COAL SULFUR CONTENT

The following discussion of the response of the bed to transients in coal sulfur content and dolomite feed rate, as predicted by the model will elucidate the processes controlling the response of the bed. This will provide an understanding of the advantages and disadvantages of the candidate control systems evaluated in the next section. This discussion will also address certain aspects of bed chemistry not discussed previously.

All figures shown in this section are results of exercising the mathematical model for the PFB power plant. The load control system was deactivated for these results to evaluate only the transient that results from changes in bed properties. An example is the effect of the calcination reaction on bed temperature and power output.

Figure 14 shows the changes in retention and the average bed utilization following a step change in the coal sulfur content from 1.95% to 3.9%. The step change represents a change in the Ca/S ratio from 1.48 to 0.74. The utilization and retention curves show considerably different trends. The retention curve shows a distinct inflection point while the utilization curve does not. It simply asymptotically approaches its new steady-state value. Both curves are algebraically related. The retention is a function of the integral of the product of the reaction rate constant and the bed population distribution. The average utilization is simply a molar average, derived from the instantaneous bed population distribution.

Another important point on this figure is the time required to approach the new steady state value. Approximately 20,000 s (5.6 hr) are required. This is an extremely long time compared to any other transient that will occur in a PFB power plant.

Following the step change of coal sulfur, the percentage of sulfur retained in the bed does not abruptly change, although the amount of sulfur released in the bed increases by a factor of two. This is a result of the following properties of the sulfur release and capture process:

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- The sulfur capture reaction is first order with respect to sulfur dioxide
- Sulfur capture is a weak function of the shape of the sulfur generation function

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The first assumption has been commonly accepted. The second is justified by the parametric analysis of the sulfur generation function presented in a previous section. This analysis showed that even large changes in the sulfur generation function did not significantly affect the sulfur retention. In reality, the sulfur dioxide generation function may change shape, but it is unlikely that it will change enough to significantly change the percentage of sulfur retained in the bed.

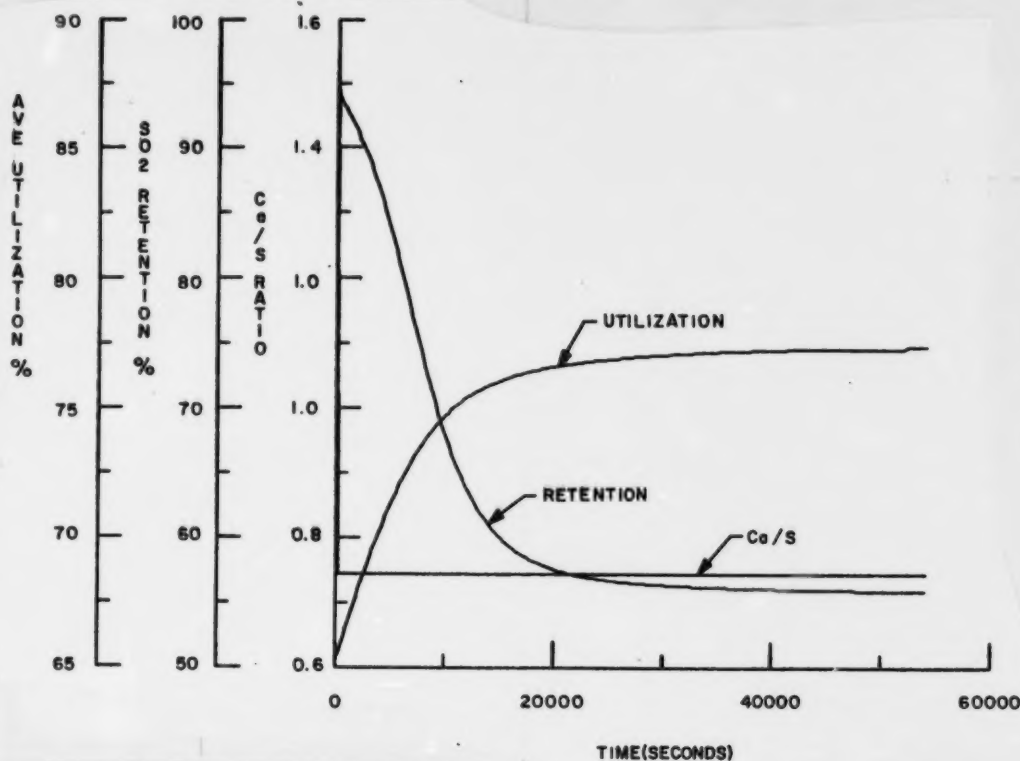


Figure 14. Response of sulfur retention and average utilization following a step change in coal sulfur content from 1.95% to 3.9% at 400s (Ca/S from 1.48 to 0.74).

The important point is that the percentage of sulfur retained in the bed does not change rapidly irrespective of rapid changes in the amount of sulfur released in the bed. The retention will change only when there is a change in the bed population distribution. This point is used later in the selection of the optimum control system.

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Figure 15 shows how the transient in coal sulfur content will affect the power and temperature of the bed. Throughout this transient condition, the coal heating value and coal flow rate were maintained at constant values. In spite of this, the bed temperature and power output rose quickly, then slowly fell to a value slightly above their initial value. The initial rise was caused by the initial increase in the amount of sulfur absorbed. Since the sulfation reaction is exothermic, more heat is released in the bed, which causes the temperature and power output to increase. The increase is small, although the transient represents a radical change in the coal sulfur content.

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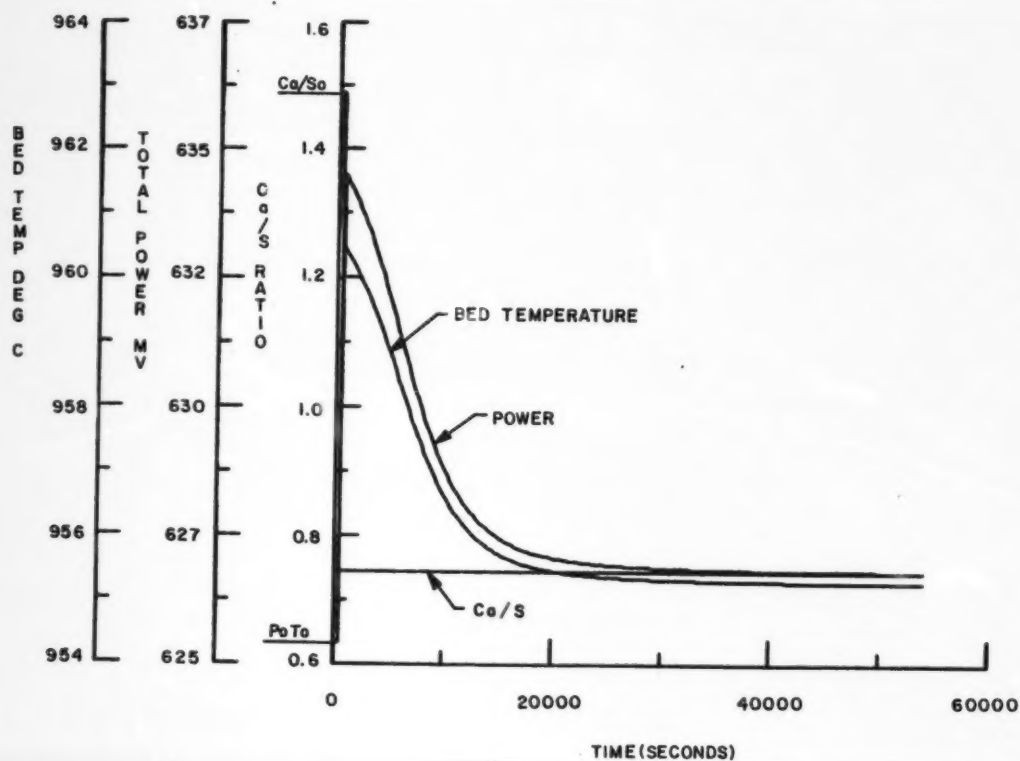


Figure 15. Transient response of bed temperature and power following a step change in coal sulfur content from 1.95% to 3.9% at 400 s (Ca/S from 1.48 to 0.74).

Following the initial increase there is a long-term decrease in the power output and bed temperature. This decrease is caused by the decrease in the rate of sulfur absorption as the retention decreases, i.e., a decrease in the rate of the exothermic sulfation reaction.

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5.2 STEP CHANGE IN DOLOMITE FLOW RATE

Step changes in dolomite feed rate show similar trends in the change in retention and other parameters. Figure 16 shows the change in retention and average bed utilization following a step decrease by a factor of two (at $t = 400$ s) in the dolomite flow rate and offtake rate. This results in a step change in the calcium sulfur ratio from 1.48 to 0.74. The transient change in retention and utilization is almost identical to that shown in Figure 14. For closer comparison the normalized retention curves are shown together on Figure 17. The similarity is not a coincidence but a result of the fact that changes in coal sulfur and changes in dolomite feed have nearly the same effect on the bed population distribution. This similarity in effect on population distribution will be illustrated later in this report. The differences that appear are a result of second order effects such as small changes in temperature and excess air.

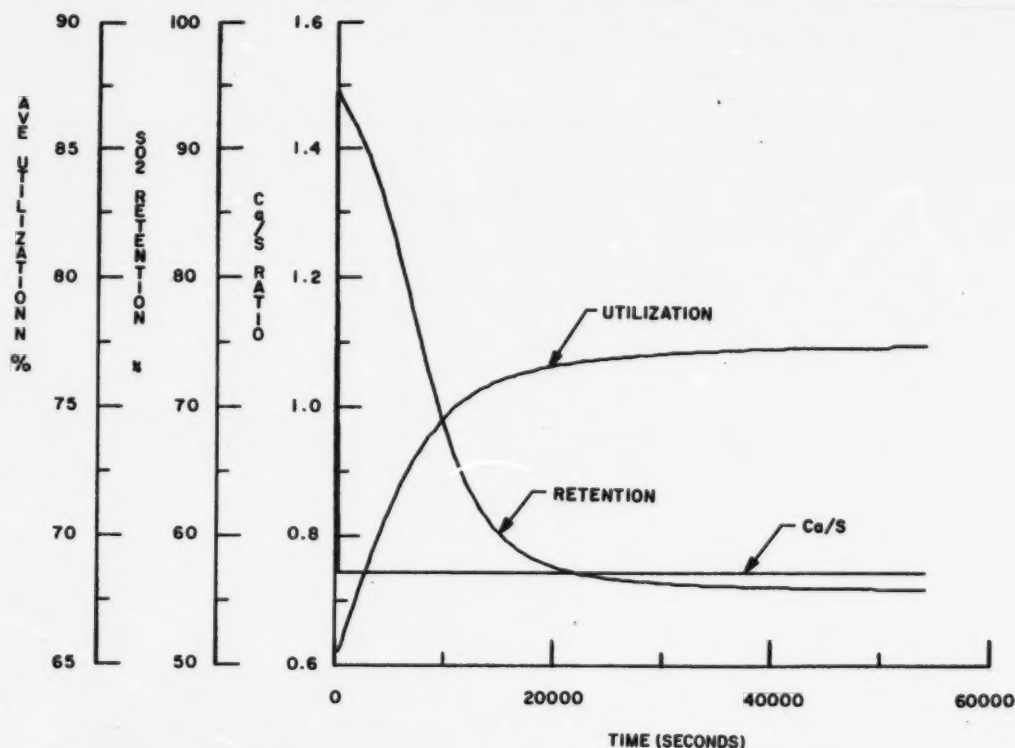


Figure 16. Transient response of sulfur retention and average utilization following a step change in dolomite flow rate at 180 s (Ca/S from 1.48 to 0.74).

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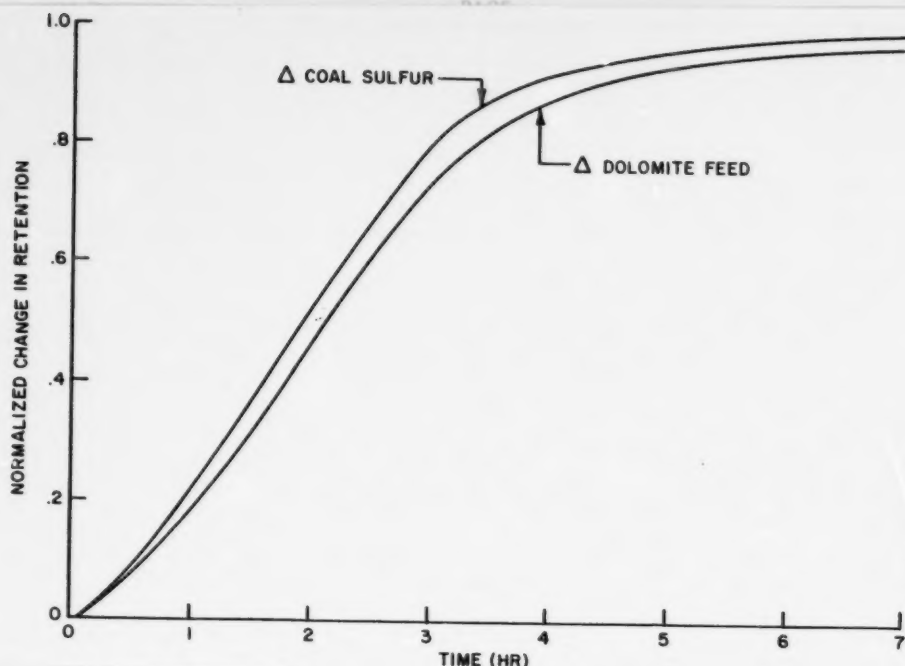


Figure 17. Normalized change in retention for a step change in Ca/S ratio of 1.48 to 0.74 for changes in coal sulfur content and dolomite flow rate.

The power output and bed temperature change for the transient in dolomite flow rate are shown in Figure 18. A trend similar to Figure 15 is seen. The temperature rises quickly following the step change, then gradually decreases. The increase in temperature is due to a rapid decrease in the endothermic calcination reaction. The gradual decrease is caused by a decrease in the exothermic sulfation reaction as the retention decreases.

5.3 VARIATION OF BED RESPONSE

The response of the bed to step changes is nonlinear. Figure 19 shows the normalized response of retention following two step changes in coal sulfur. One is a change from a coal sulfur content of 3.9% to 1.95% (Ca/S 0.74 to 1.48). The other transient is the reverse of the first (Ca/S 1.48 to 0.74). Note the difference in the response of retention. Although both transients have the same end points, the response is significantly different. The initial change in retention is much more rapid for the change that increases Ca/S ratio. However, the transient response for a decrease in Ca/S ratio initially has a slow response, but reaches equilibrium conditions sooner than the increase in Ca/S ratio. This effect is due to changes in the population distribution of the bed and will be discussed in the next section.

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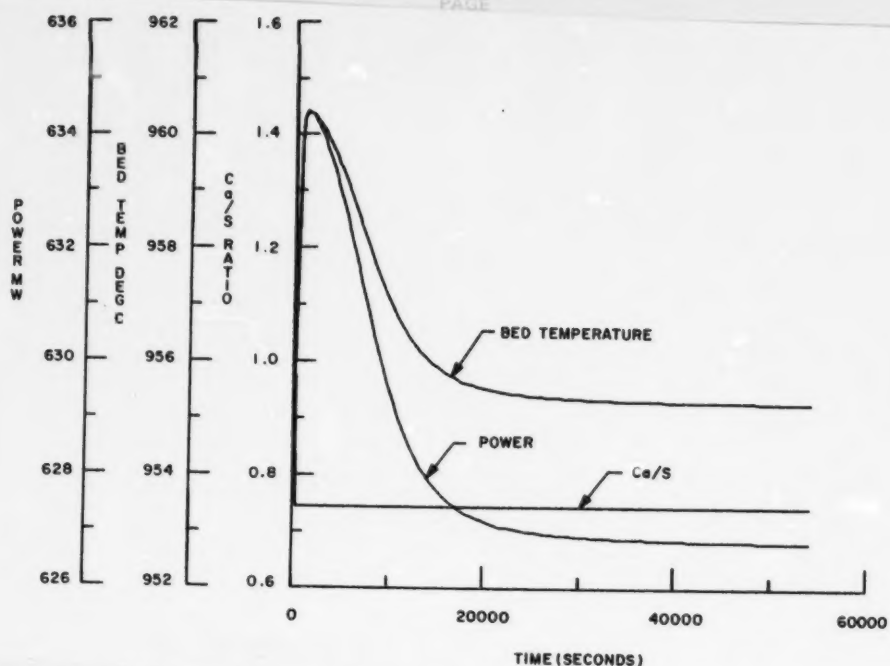


Figure 18. Transient response of bed temperature and power following a step change in dolomite flow rate at 180 s (Ca/S from 1.48 to 0.74).

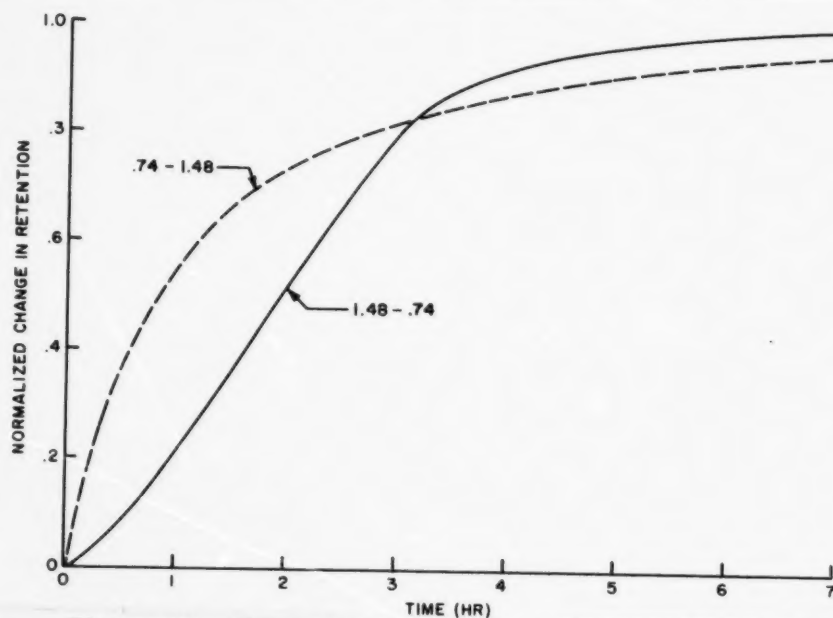


Figure 19. Normalized change in retention as a function of time for a step change in coal sulfur content (Ca/S, 1.48 - 0.74: Ca/S 0.74 - 1.48).

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Not only is the retention response of the bed a function of the direction of step, but it is also a function of the size of the step. Figure 20 shows the normalized change in retention following several step changes in dolomite flow rate. Increases in Ca/S ratio produce responses which are initially faster than decreases in Ca/S ratio. This trend is similar to that previously discussed. However, the response of the bed is not only a function of the directions of the response but the size of the change.

Bed Inventory Distribution

As previously described, the moles of calcium (and consequently particles) within the bed can be characterized by a distribution over size and utilization. The steady-state bed inventory distribution for a Ca/S ratio of 1.48 is shown in Figure 4. The distribution can be thought of as a three dimensional surface. This surface changes with time in response to changes in the input, offtake, or other bed conditions.

The distribution tends to peak at rather large utilizations. This is due to the rather long residence time of particles within the bed. It also indicates the need to know the reaction rates of particles to very high utilizations. Although the rate at large utilizations is small, the population is large. Consequently, these particles absorb a significant amount of sulfur.

Smaller sizes peak at larger utilizations. This is due to the larger reaction rates of the small particles.

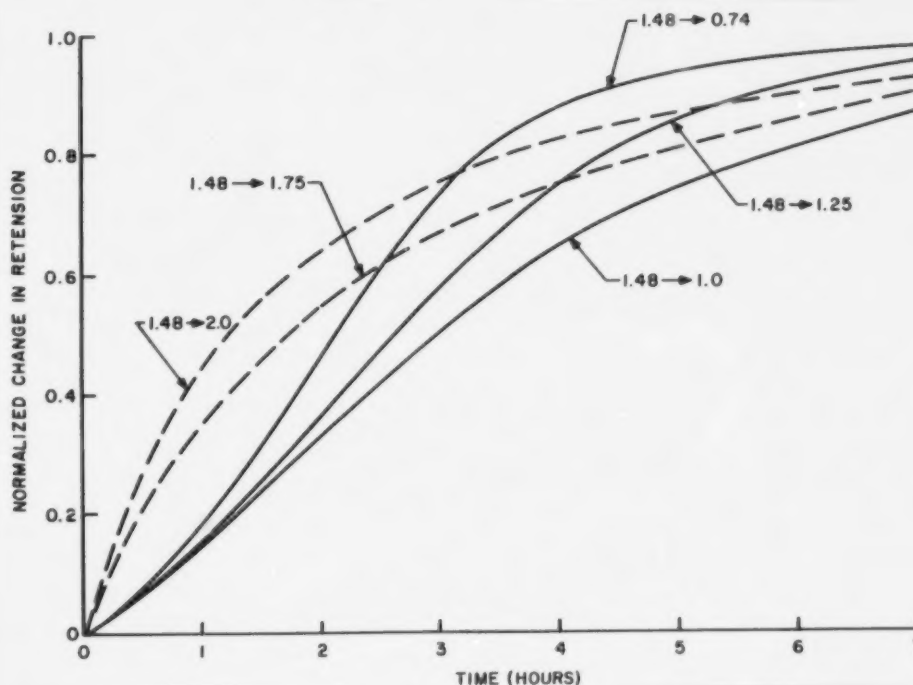


Figure 20. Normalized change in retention as a function of time for various step changes in dolomite feed.

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The population distribution ends at 300 microns. As shown in Appendix A, particles below this size are quickly elutriated from the bed and do not absorb appreciable amounts of sulfur while they are in the bed. Moreover, their steady-state population within the bed is extremely small.

The equation that governs the population is Equation 3.10. In word form written for particles of a particular size and utilization, the equation is

$$\begin{array}{rcccl} \text{Rate of} & \text{Rate of} & \text{Rate of} & \text{Rate of} & \text{Rate of Production} \\ \text{Inventory} = & \text{Feed} & - \text{Offtake} & - \text{Elutriation} & + \text{of Fine Particles} \\ \text{Change} & (1) & (2) & (3) & \text{Due to Attrition} \\ & & & & (4) \end{array}$$

$$\begin{array}{rcc} \text{Net Rate of} & \text{Net Rate of} \\ + \text{Change Due} & + \text{Change Due to} \\ \text{to Sulfation} & \text{Attrition} \\ (5) & (6) \end{array}$$

Understanding the terms in this equation is important because it will be referred to several times in the next few pages to explain how processes in the bed interact. The physical significance of the first three terms and the fifth term on the right side is obvious. The fourth term is the rate of generation of small particles by attrition. The sixth term is the rate of change due to the shrinking of particles caused by attrition. Not all the terms are applicable over the entire population range. For example, the first term, Rate of Feed, is only finite for particles of the lowest utilization.

Table 5 shows the population size distribution for the dolomite feed material and the bed inventory. The table shows very little difference between the two. It can be concluded that the terms in the population equation that affect the size distribution of the inventory are rather small. For a basic understanding of the processes occurring following a transient, terms 4 and 6 of the inventory equation can be thought of as negligible. Moreover, term 3 can also be neglected because it primarily affects small particles (below 300 microns). Consequently, only terms 1, 2, and 5 are important in understanding the transient response of sulfur capture.

Although the full population distribution was shown in Figure 4, it is valuable to examine the distribution of particles over utilization for a very small size range. Figure 21 shows the steady state utilization distributions for several calcium sulfur ratios for particles of 1050 microns $\pm$ 87 microns. The buildup of particles at high utilizations is more pronounced for low Ca/S ratios than high Ca/S ratios.

Since the results shown in Figure 21 are for steady state conditions, the term on the left side of the population equation is zero. In addition, the rate of feed of particles is only a source term for particles of the lowest utilization and is zero everywhere else. Consequently, for most utilization ranges the rate of offtake, Term 2, is balanced by the net rate of change due to sulfation, Term 5. Surprisingly, at low utilizations, Term 2 is small compared with Term 5. This leads to an interesting conclusion that the rate of

TABLE 5. COMPARISON OF FEED SIZE DISTRIBUTION AND BED INVENTORY DISTRIBUTION

Mid-size (μm)	Feed Size Distribution (% Ca molar)	Bed Size Distribution* (% Ca molar)	Bed Size Distribution** (% Ca molar)
2100	2.00	1.99	1.70
1925	2.00	1.99	1.70
1750	4.00	3.97	3.40
1570	7.00	6.96	5.96
1400	10.00	9.93	8.51
1225	12.00	11.92	10.21
1050	15.00	14.90	12.68
875	18.00	17.89	15.32
700	18.00	18.10	20.09
525	10.00	10.15	13.37
350	2.00	2.20	6.99

*Base case: 3.9% S, Ca/S = 1.48

**Data represents worst case: 3.9% S, Ca/S = 0.74

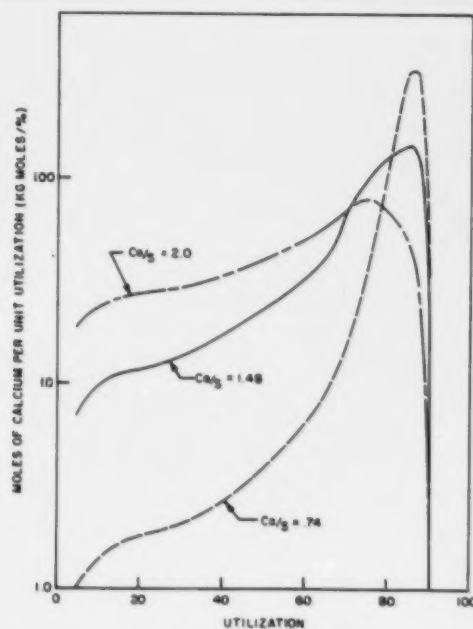


Figure 21. Utilization distributions of $1050 \mu\text{m} \pm 87 \mu\text{m}$ Particles for steady state Ca/S ratios of 2.0, 1.48 and 0.74.

particles changing from one utilization to the next is constant over most of the utilization distribution and is equal to the rate of feed of particle in the size range of interest. If this is true, it follows that for most of the utilization population distribution, the amount of sulfur absorbed per unit utilization is constant. This point is illustrated in Figure 22, which shows the absorption rate, $K_{ij}n_{ij}$ (Equation 3.9) as a function of utilization for 1050, 1400, and 525 micron particles and a Ca/S ratio of 1.48 and 0.74. The value of $K_{ij}n_{ij}$ is remarkably constant for Ca/S ratio of 0.74, but it is far from constant for a Ca/S of 1.48. It follows that the steady state utilization distribution is inversely proportional to the rate constant for low Ca/S ratios like 0.74.

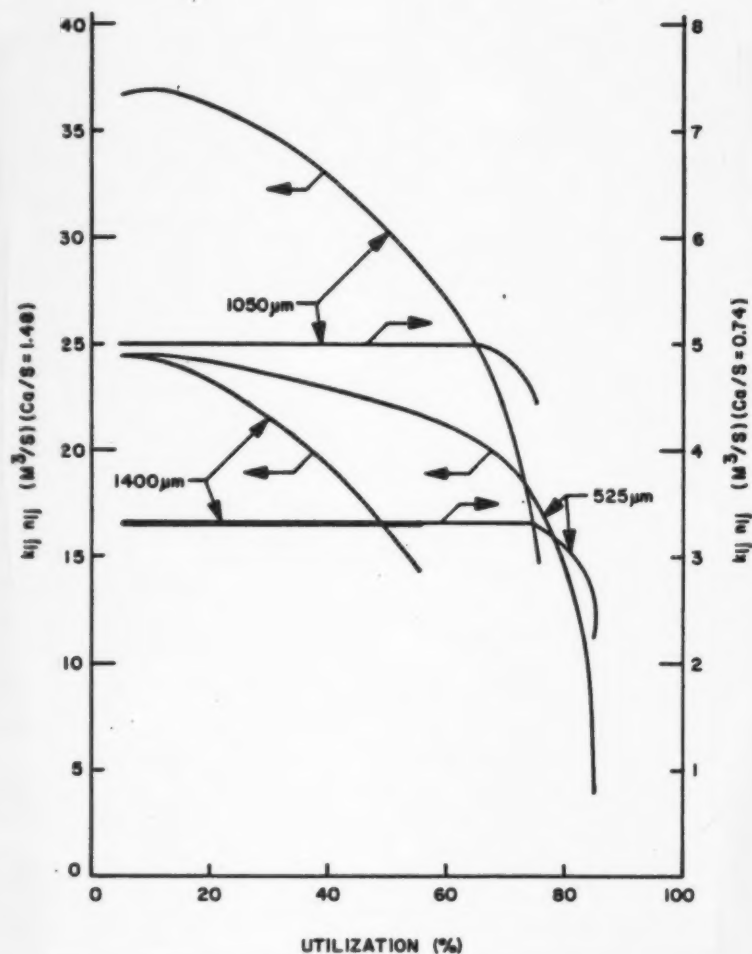


Figure 22. The value of $k_{ij} n_{ij}$ as a function of utilization for Ca/S of 0.74 and 1.48 for various size particles.

Another finding is that the utilization population distribution is not a strong function of the absolute molar flow rate of calcium and sulfur as long

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as their ratio remains the same. Table 6 shows the utilization population distribution for a Ca/S ratio of 1.48 for two different feed rates. This fact is used in choosing the preferred control concept.

TABLE 6. UTILIZATION DISTRIBUTION FOR Ca/S RATIO OF 1.48 PARTICLES OF $1050 \pm 37 \mu\text{m}$, FOR TWO SULFUR FEED RATES

Mid Utilization† (%)	3.9% S Coal (K _g moles)	1.95% S Coal (K _g moles)
5	7.3	7.0
15	10.5	10.1
25	12.2	11.7
35	14.9	14.4
45	21.5	21.0
55	26.9	26.0
65	38.6	37.7
75	97.6	98.1
85	144.3	151.2
95	1.3	0.4

† $\pm 5\%$

Transient changes in the population distribution have a distinct wave pattern. Figure 23 shows how the population distribution changes when the dolomite feed and offtake rate are decreased. Note that the population of the lower utilization particles is affected first. This effect is somewhat analogous to changes in the birth rate of the U.S. The change is first felt by younger age groups, and then propagates to older age groups.

An observation of major significance is that changes in the sulfur input to the bed produce the same wave effect. Figure 24 shows how the changes in the sulfur feed rate affect the population distribution. The dashed curves representing a change in Ca/S ratio from 1.48 to 0.74 by changing the sulfur flowrate. This is the same change in Ca/S ratio as the performed for the results in Figure 23, but the change was accomplished by changing the coal sulfur content instead of dolomite flow rate.

It is easy to see why changing the dolomite feed rate would cause a wave effect in the population, but it is not as obvious for changes in sulfur input. To understand this, one must realize that particles are continually moving from low utilizations to high utilizations as a result of absorbing sulfur. When additional sulfur is added to the bed, the rate of sulfur absorption increases. The rate of particles moving to higher utilizations also increases.

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If the feed rate is not increased in proportion to this increased rate of movement to higher utilizations, the population of particles in the lower utilizations must decrease to a new steady state value.

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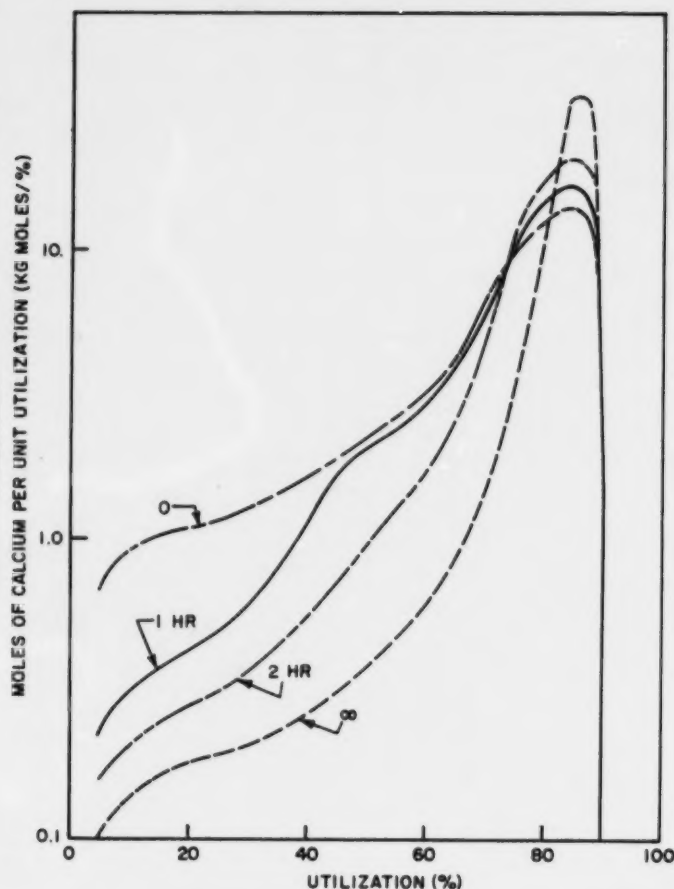


Figure 23. Transient population utilization distribution for a step change in dolomite from Ca/S 1.48 to 0.74 for $1050 \pm 87 \mu\text{m}$ particles.

Also shown in Figure 24 is the reverse transient, i.e., a decrease in sulfur input from a Ca/S ratio of 0.74 to 1.48. Again, a wave effect can be seen traveling from lower to higher utilizations. The difference between the transient population distributions for the two cases should be noted. Although the end points of the changes are the same, the transient distribution for a change in Ca/S ratio will never be the same as for the reverse direction. This irreversible effect causes the nonlinear response of retention (Figure 19) as a function of direction of change.

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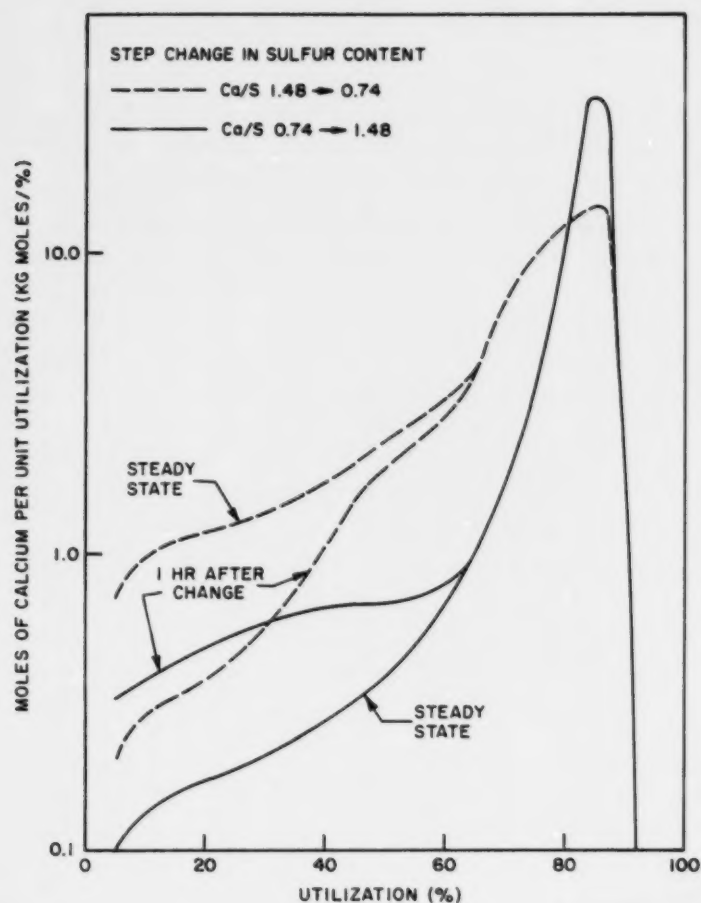


Figure 24. Utilization distributions of $1050 \pm 87 \mu\text{m}$ particles for steady state Ca/S ratios of 1.48 and 0.74, and transient distributions for 1 hour after a step change in coal sulfur content.

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SECTION 6

ASSESSMENT OF COAL SULFUR MONITOR

6.1 INTRODUCTION

To ensure sulfur removal while limiting dolomite consumption, the content of the incoming coal is measured as frequently as possible for two reasons:

- To determine the amount of sulfur injected into the combustor per unit time
- To determine the allowable limit of SO_2 emissions

It is a complicating fact that the composition and properties of coal are highly variable, even within a single piece, so that an accurate measurement of the physical and chemical characteristics of a coal stream requires essentially continuous monitoring of as large a fraction of the feedstream as possible.

Sulfur monitoring of the coal is also required to assure compliance with the SO_2 emission limits for power generation facilities. Figure 25 shows the most recent EPA SO_2 emission limits for utility coal fired boilers generating 250 MBtu/hr or more. As shown, the allowable emissions (in lb $\text{SO}_2/10^6$ Btu) are a function of the sulfur content of the coal. Accurate knowledge of coal sulfur levels will facilitate compliance with such a standard without wasteful excesses of materials used for SO_2 control.

This section reviews traditional laboratory analyses of coal and evaluates alternative available monitoring systems for determining the sulfur content of coal on a continuous basis. Particular attention will be given to a nuclear activation technique that offers the potential for continuous coal feed monitoring. The relative advantages and disadvantages of the various systems will be considered as well as the feasibility of and future work required on promising systems.

6.2 TRADITIONAL COAL ANALYSIS

The testing of coal to determine those chemical and physical properties which affect its performance in a combustion system has historically been performed in accordance with procedures established by the American Society for Testing and Materials (ASTM, 1977). Forty Standards are listed by ASTM for the analysis of coal. Of these, three are specifically related to the testing for total sulfur content: D2234-76 "Collection of a Gross Sample of Coal," D2013-72 "Preparing Coal Samples for Analysis" and D3177-75 "Total Sulfur in the Analysis Sample of Coal and Coke."

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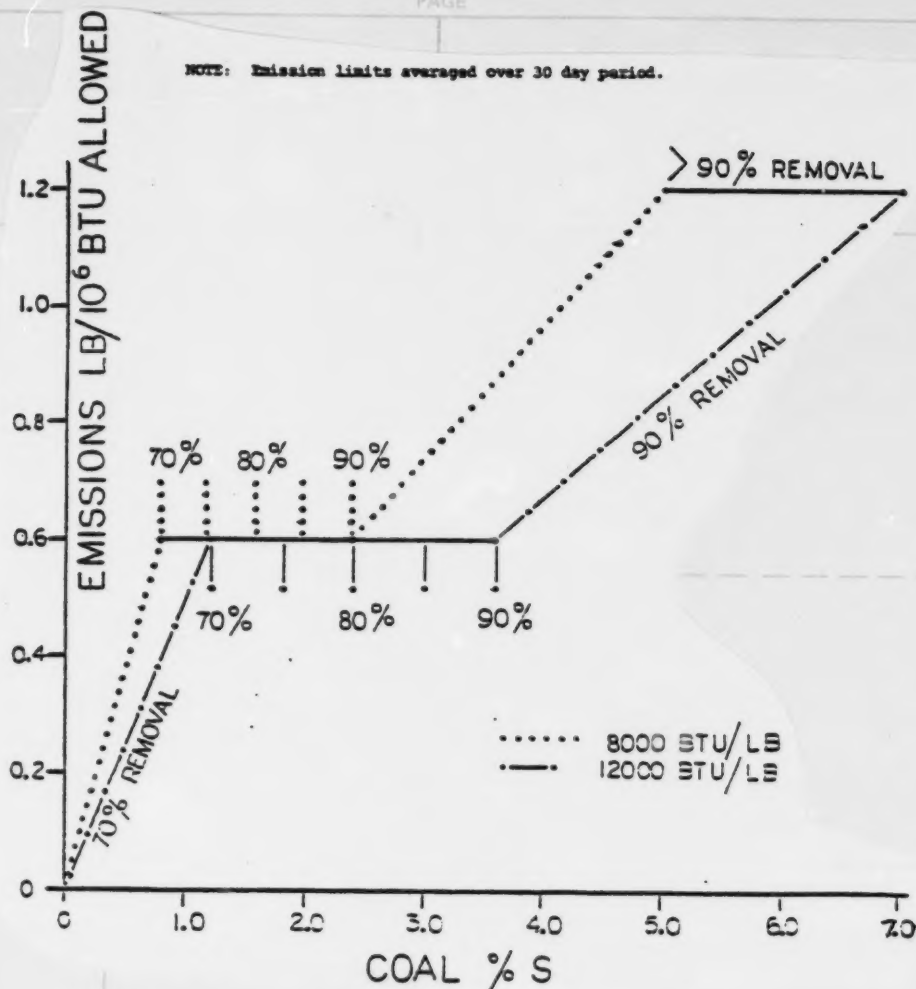


Figure 25. SO₂ NSPS - Utility Coal Boilers (Code of Federal Regulations, Title 20, Section 6D, June 11, 1979)

Sampling of coal is a complex procedure, primarily because of the non-homogeneous nature of the coal itself. Careful sampling techniques must be employed to ensure that the relatively small portion selected for analysis is representative of the entire lot. For example, as few as 15 one-kilogram samples may be taken from a 900 metric ton lot of coal (having a top size of 16 mm) and the composite of these samples (called a gross sample) is dried, crushed and separated into a 50-gram quantity from which one gram is actually used in the laboratory analysis. For this general purpose sampling procedure, a precision of $\pm 10\%$ of the average sulfur content can be obtained in 95 out of 100 cases by taking gross samples repeatedly from the one 900 metric ton lot, and by making one sulfur determination from each gross sample. For larger size coal, larger size samples must be taken to obtain the same precision

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while a greater precision can be achieved by taking more samples (both individual and gross). This latter point is demonstrated in Figure 26, which shows the effect of combining individual samples on the indicated sulfur content of coal processed at Morgantown Energy Research Center (MERC) (Stewart, 1978). The graph to the right shows, in succession, the sulfur level measured from composites of 2, 4, 10, and 20 samples. As indicated, the average sulfur level remains the same for each case, whereas the variation from the average (i.e., the standard deviation) becomes smaller as more samples are combined prior to analysis.

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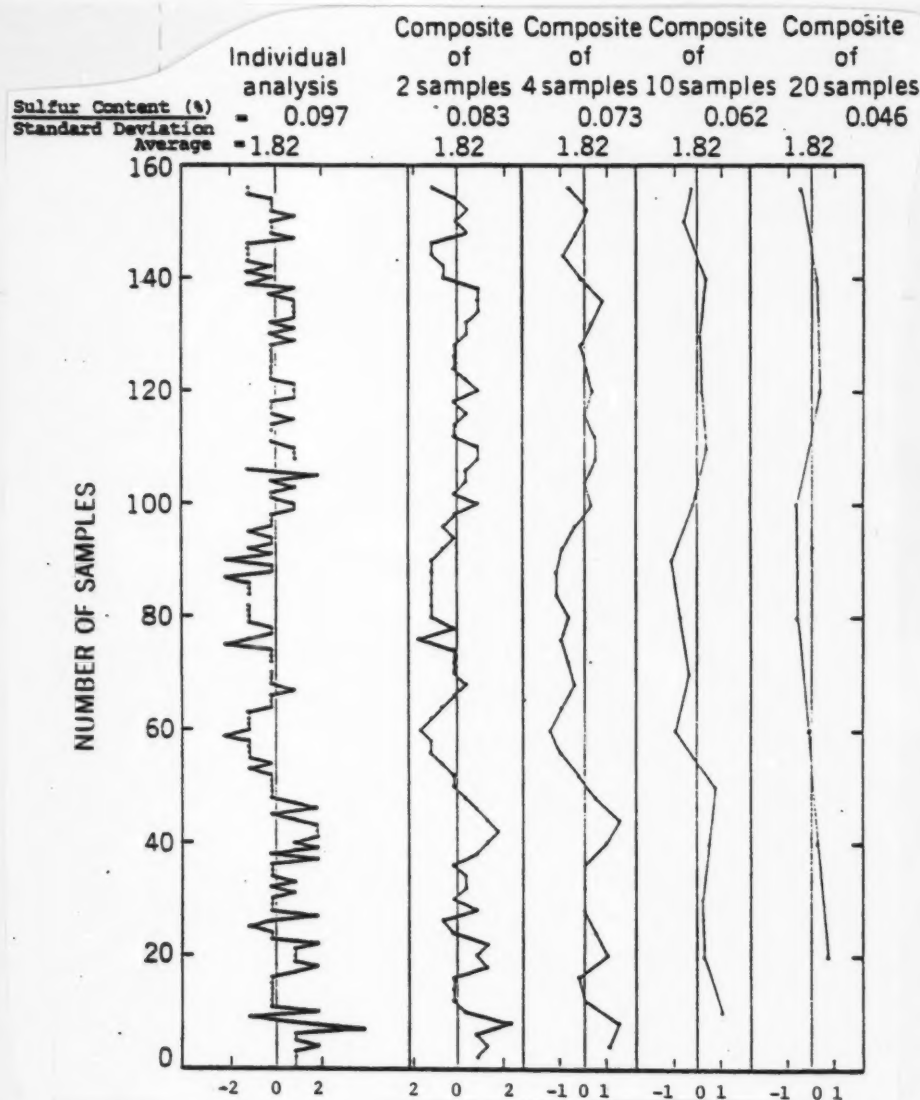


Figure 26. Results of averaging various numbers of coal samples (Stewart, 1978).

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Once the individual coal samples have been taken and processed to yield a suitable analysis sample, the total sulfur content of the coal is determined by one of the three methods specified in ASTM standard D3177-75. The three techniques (Eschka, Bomb Washing, and High Temperature Combustion) are wet laboratory analyses which involve either the precipitation or titration of sulfates formed as the result of combustion of the coal sample. However, all three methods have similar disadvantages: (1) the actual sample tested is one gram or less, (2) the minimum time to obtain an analytical result exceeds 15 minutes, and (3) the limit of accuracy varies from $\pm 0.05 \pm 0.20\%$ (absolute), depending on the method used and the sulfur content of the coal.

The determination of the sulfur content in coal by the ASTM methods (including sampling, preparation and actual laboratory analysis) is a process which can require several hours to complete. In addition, what is sought is not the average sulfur content of the coal, but a measure of the instantaneous sulfur content of the coal being fed to the fluidized bed. This involves taking more or larger samples, which requires more processing and in turn delays the results of the analysis even further. These substantial delay times restrict the usefulness of the traditional sulfur analysis for use as a continuous sulfur monitor.

6.3 INSTRUMENTAL TECHNIQUES

Nondestructive sulfur analysis of coal is preferred because the heating value of the coal is not lost and larger samples are submitted for analysis. In such cases, the need for sample preparation is minimized or even eliminated. However, these techniques, as applied to coal, are developmental in nature and all depend on nuclear or atomic principles with attendant radiation shielding needs. On the other hand, a large number of techniques are commercially available if the sulfur in the coal can be converted to a liquid or gaseous state. In such cases, the major problem lies in converting the sulfur to a form amenable to detection in a continuous manner. Several potential instrumental techniques are reviewed in the following sections, along with relative advantages and disadvantages of each. These are followed by an evaluation of the various techniques presented and the selection of the most promising instrumental method.

Destructive Analyses

The primary disadvantage common to destructive analyses lies in the conversion of the sulfur in coal to SO_2 . In theory, this is possible by combusting a portion of the coal sample and analyzing the gaseous products of SO_2 . In practice, however, operating a combustor would require separate combustor control and an elaborate feed system. In addition, the coal burned there would be wasted, unless the heat could be recovered for some application in the plant. Finally, there are the problems of controlling SO_2 emissions from the combustor and insuring a representative coal sample is used. Assuming these can be overcome, the following instrumental techniques could be used to detect the SO_2 produced in the sample combustor (Hollowell et al., 1973).

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Conductimetric Analysis--

A conductimetric analyzer measures the conductance of a solution into which SO₂ has been absorbed. When SO₂ is dissolved in a solution of distilled water or dilute, acidified hydrogen peroxide, ions are formed which cause an increase in the electrical conductance of the solution proportional to the amount of SO₂ dissolved. The advantages of these devices are high sensitivity, fast response, minimal maintenance and simple operation. However, they are susceptible to gases other than SO₂ that form (or remove) ions in solution.

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Colorimetric Analysis--

Colorimetric analyzers operate on the principle of Beer's Law by measuring the optical absorption of a solution. Beer's Law can be expressed as:

$$I = I_0 e^{-\alpha c l}$$

where:

I = signal strength after passage through absorbing medium

I₀ = signal strength before passage through absorbing medium

K = constant

α = absorption coefficient of absorbing medium at wavelength being absorbed

c = concentration of absorbing medium

l = optical path length

For dilute concentrations, the absorbance is linearly proportional to the concentration of the colored species. The SO₂ is converted to sulfurous acid, which is in turn detected by a dye. The absorption of light in the dye is then a measure of the SO₂ concentration. This method is simple and highly sensitive. However, it does involve wet chemistry and its attendant problems: the need to replenish reagents, the need to periodically clean components, the corrosive atmosphere that exists within the device, and the relatively long time required for the color intensity to approach its asymptotic value. In addition, the color intensity is sensitive to temperature, pH, purity of reagents and age of solutions.

Amperometric Analysis--

Sulfur dioxide reduces halogens to halides and amperometric analyzers measure the amount of electrical current required to maintain a constant halogen concentration. This current is then proportional to the amount of SO₂ absorbed. The major advantage of this type of device is the minimal maintenance required: since the halogen is regenerated, there is negligible loss of reagent. On the other hand, it is also sensitive to other species that reduce halogens, most notably sulfur-containing compounds. This may actually be an advantage, since it would measure the total sulfur content regardless of the form, be it SO₂, H₂S, organic sulfides or organic disulfides. However, this analysis method is not considered attractive because it has the slowest response time of all the instrument types evaluated.

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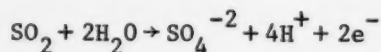
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Electrochemical Transducer Analysis--

The electrochemical transducer (ECT) avoids the wet chemistry of the conductimetric, colorimetric and amperometric analyzers by using a sealed unit within which all electrochemical reactions occur. As shown in Figure 27, SO₂ diffuses through a semipermeable membrane and is dissolved in the thin film electrolyte. The SO₂ is then oxidized at the sensing electrode via the half-cell reaction:



The electrons produced are sensed as an electrical current proportional to the amount of SO₂ oxidized. The electrons are then collected at the counter electrode, where they recombine to complete the cell reaction.

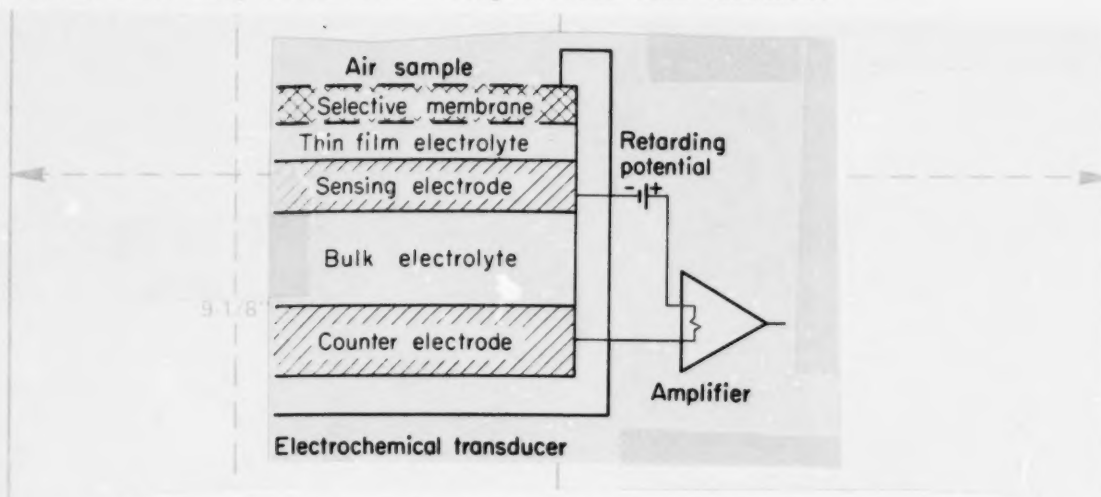


Figure 27. Electrochemical transducer analyzer. (Hollowell et al., 1973. Reprinted with permission from Analytical Chemistry, Vol. 45, No. 1, 1973. Copyright by the American Chemical Society.)

ECT analyzers are simple, rapid, portable, light, and have low power consumption. Selectivity to SO₂ is achieved by judicious choice of the semipermeable membrane. However, performance does degrade with time, which requires frequent recalibration and eventual rejuvenation or replacement. Also, the sample must be pushed, rather than pulled, through the analyzer to avoid pulling the membrane away from the thin electrolyte. At this time, ECT is not considered to be practical for large scale coal analysis.

Flame Photometry--

In the flame photometric detector (FPD), SO₂ is fed into a hydrogen-rich flame and the 394 nm sulfur emission band selected by a narrow band optical filter, as shown in Figure 28. FPD analyzers are characterized by low maintenance, high sensitivity, fast response and simple design. A major disadvantage is the need for compressed hydrogen to produce the flame. Another is the need to dilute the SO₂ concentration to within the detector range when

using the instrument for source monitoring (no dilution is normally required when using FPD in ambient air monitoring). Finally, because the photomultiplier tube output is logarithmically proportional to the sulfur concentration, electronics are needed to convert the output signal to a linear display.

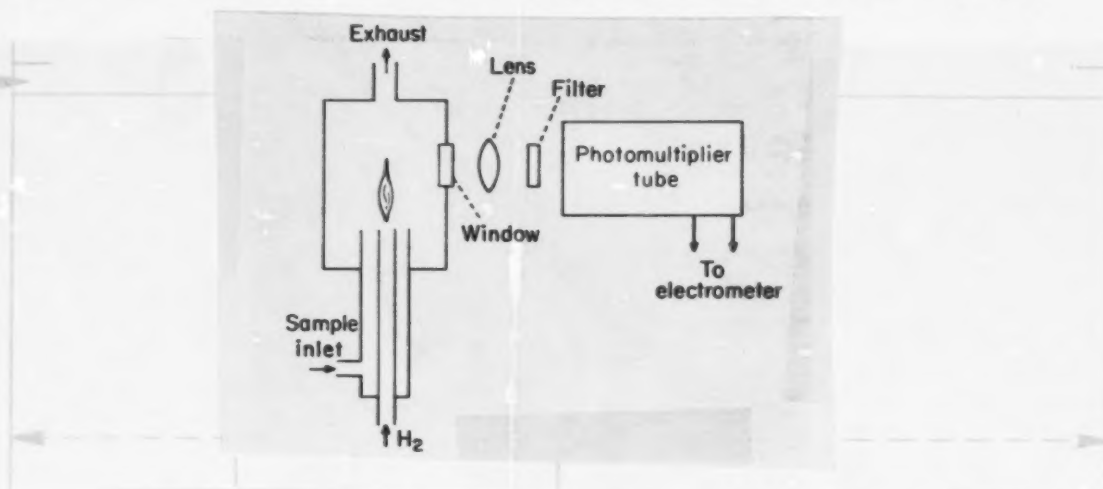


Figure 28. Flame photometric detector. (Hollowell et al., 1973. Reprinted with permission from Analytical Chemistry, Vol. 45, No. 1, 1973. Copyright by the American Chemical Society.)

Nondispersive Absorption Spectrometry--

Nondispersive absorption spectrometers are probably the most common type of SO_2 monitor in use today. They utilize broad-band spectral absorption and are sensitized to a particular gas by means of a detector, special cell or filter. This type of device may be operated in the infrared (IR), ultraviolet (UV), or visible spectral regions. A typical nondispersive infrared (NDIR) analyzer is shown in Figure 29. Infrared radiation passes through two cells: a reference cell containing a gas such as nitrogen or argon (which do not absorb IR) and the sample cell through which the SO_2 is drawn and absorbs IR energy. The resultant beams fall on a detector containing SO_2 which is divided into two chambers by a flexible but impermeable diaphragm. Because the beam passing through the sample cell loses energy due to absorption, the gas in that chamber is not heated as much as the gas in the other chamber. This heating differential results in a displacement of the diaphragm, which is then measured as a capacitance change. The infrared beams are interrupted by a mechanical chopper in order to generate a modulated signal from the capacitive detector. This signal is then demodulated, amplified and displayed.

Most NDIR analyzers are similar to the one shown in Figure 29 with some variations in the optical and detector arrangements. The primary disadvantage of NDIR instruments is interference from non- SO_2 sources; however, these can be minimized by using auxiliary absorption cells or optical filters. Nondispersive ultraviolet analyzers operate in a similar manner but are somewhat more sensitive than NDIR analyzers.

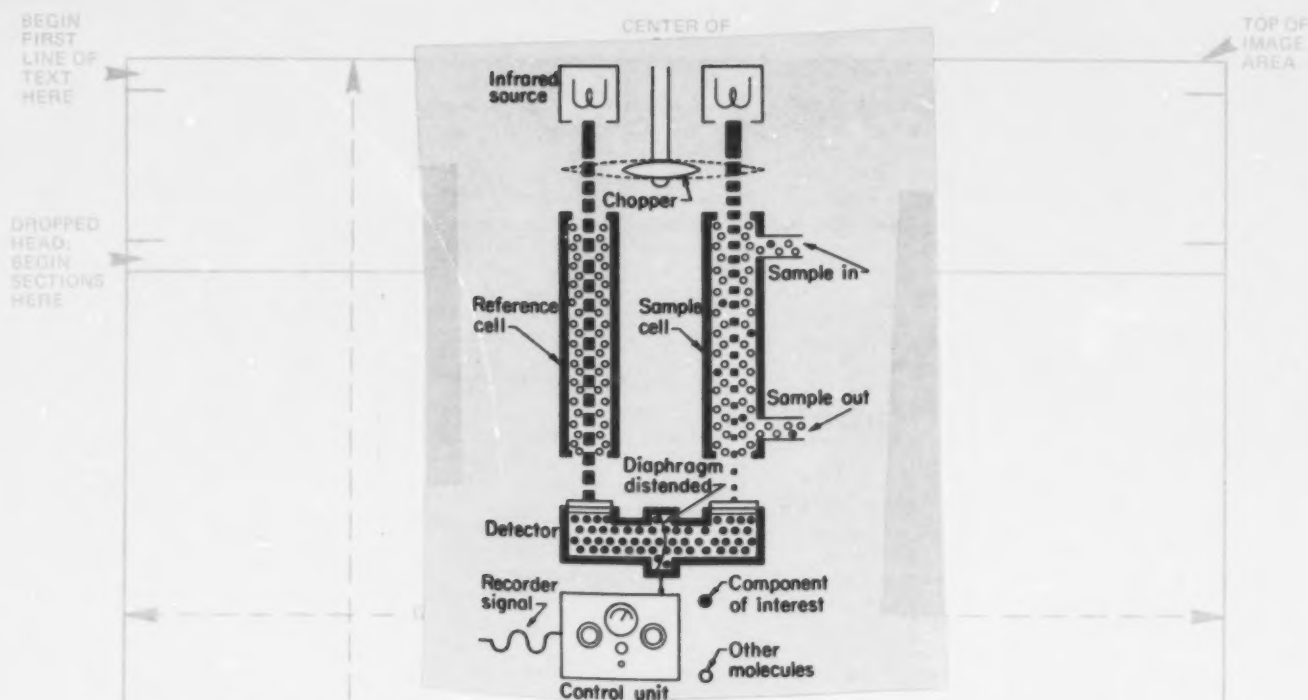


Figure 29. Nondispersive infrared analyzer. (Hollowell et al., 1973. Reprinted with permission from *Analytical Chemistry*, Vol. 45, No. 1, 1973. Copyright by the American Chemical Society.)

Dispersive Absorption Spectrometry--

Unlike the nondispersive instrument, the dispersive absorption spectrometer analyzer passes only a limited wavelength interval through the gas to be measured. Thus, it is not limited to a single preselected gas as is usually the case for nondispersive types. However, if more than one gas is present it may be difficult to select a wavelength range in which only the gas of interest absorbs energy.

Correlation Spectrometry--

A correlation spectrometer uses either a natural or artificial light source and collimates, disperses (by a prism or grating) and focuses the light onto a correlation mask as shown in Figure 30. The pattern on the mask corresponds to the absorption lines of SO_2 . If the mask is shifted relative to the incident spectrum, the photomultiplier tube will be exposed to the minimum light intensity when the mask lines are aligned with the SO_2 lines and a maximum intensity when the mask is removed. The difference in light intensities is a measure of the SO_2 concentration.

This type of analyzer has more advantages for long-line data (i.e., measuring SO_2 concentration over a long distance) and may be more useful on ambient air pollution monitoring. Also, artificial light is required for night use if natural light is not available.

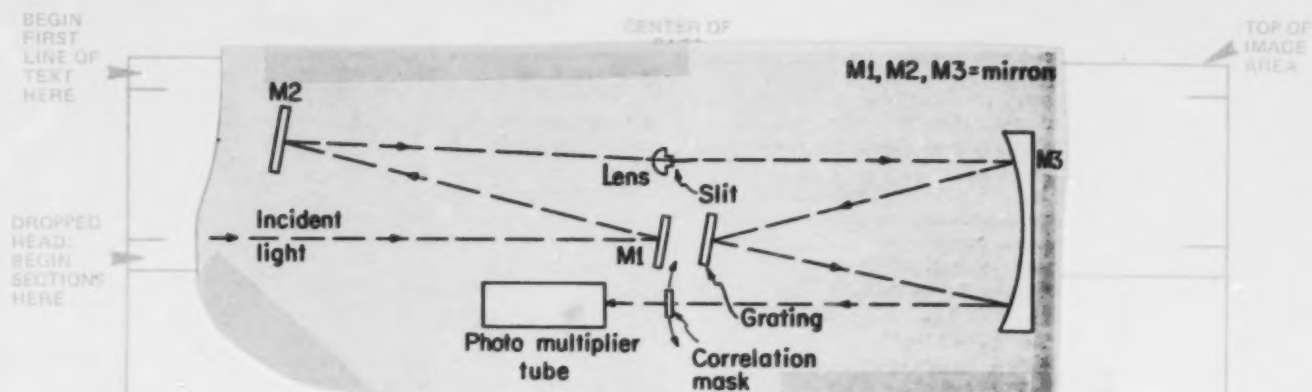


Figure 30. Correlation spectrometer for remote monitoring. (Hollowell et al., 1973. Reprinted with permission from Analytical Chemistry, Vol. 45, No. 1, 1973. Copyright by the American Chemical Society.)

The techniques discussed above represent the more common methods used for SO_2 monitoring today. Table 7 lists some of the features of SO_2 monitors commercially available. The response time is the time necessary for a 90% reading after a step positive input. Note also that the costs are not current and should be used for comparative purposes only. It is apparent from Table 7 that there are a number of commercially available instruments capable of continuous (i.e., having a response time of several minutes or less) monitoring of SO_2 provided that the sulfur in coal can be converted to SO_2 effectively. Herein lies the difficulty with destructive analysis methods. Great care must be taken that the sample analyzed is fully representative of the sample itself. Condensation of vapors or incomplete combustion can markedly affect the accuracy of the analysis. Appropriate sample conditioning must also be included. Such problems coupled with the task of representative sample selection become serious concerns when attempts are made to carry them out on the scale required for large commercial power plants.

As discussed previously, oxidizing the sulfur in coal to SO_2 in a combustor has some serious difficulties. One possible alternative would be to gasify the portion of the coal to be analyzed rather than combusting it. The energy content of the coal could then be recovered by burning the gas after sampling has been performed. The sulfur in the coal would be converted predominately to H_2S , with a lesser amount forming the chemical compound COS. Referring again to Table 7, there are several of the instruments previously discussed that could be used to detect H_2S or total sulfur, such as colorimetric, electrochemical transducer, and flame photometric. On the other hand, a gasification system would also require very sophisticated controls and is probably too developmental at this time to be considered practical for large scale of power plant applications. In addition, many of the disadvantages of a combustor, such as controlling sulfur emissions and ensuring the injection of a representative coal sample, are also present in a gasifier.

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TABLE 7. SO₂ STATIONARY SOURCE MONITORS

(Hollowell et al., 1973. Reprinted with permission from Analytical Chemistry, Vol. 45, No. 1, 1973. Copyright by the American Chemical Society.)

Principle of operation	Manufacturer	Model	Measuring range, ppm	Response time	Cost	Multi-parameter capability
Conductimetric	Calibrated Instruments	Mikrogas MSK	1.4-8000	2 min	\$5615	CO ₂
Colorimetric	Houston Atlas	875	0.01 ppm-100%	2 min	\$4420	Total sulfur, H ₂ S
Amperometric (coulometric)	Barton	286	0.05-1000	5 min	\$4150	H ₂ S, mercaptans
	Barton	400	0.05-1000	"	\$5425	H ₂ S, mercaptans
Electrochemical transducer	Dynasciences	SS-330	10-5000	90 sec-3 min	\$2000	NO ₂ , NO ₂ , CO, CH ₂ O
	Envirometrics	NS-200	0.01-20,000	5-10 sec	\$1750	NO ₂ , NO ₂ , H ₂ S, CO
	Theta Sensors	US-5000	"-5000	20 sec	\$3500	NO ₂
	Theta Sensors	LS-800	"-5000	13-20 sec	\$1150	NO ₂
Flame photometric detector	Meloy	FSA 190	25-10,000	12 sec	\$8500	Total sulfur and phosphorus
Nondispersive absorption spectroscopy	Beckman (IR)	IR-315 B	200 ppm-20%	0.5 sec	~\$2900	CO, NO, NO ₂ , etc.
	Bendix (IR)	UNOR 2	"-50%	3 sec	\$3403	CO, NO, NO ₂ , etc.
	Bendix (IR)	UNOR 6	"-2000	4 sec	\$2680	CO, NO, NO ₂ , etc.
	Calibrated Instruments (IR)	SC/LC	5 ppm-50%	~15 sec	\$2995	CO, NO, NO ₂ , etc.
	DuPont (UV)	460	8-5000	15 sec	\$8175	NO ₂ , NO ₂ , Hg, etc.
	Intertech (IR)	Uras 2	1.0 ppm-100%	0.5 sec	\$3280	CO, NO, NO ₂ , etc.
	Mine Safety Appliances (IR)	LIRA 200	"-100%	5 sec	\$3570	CO, NO, NO ₂ , etc.
	Mine Safety Appliances (IR)	LIRA 300	"-20%	5 sec	\$1795	CO, NO, NO ₂ , etc.
	Monitor Labs (IR Emission)	8200	"	"	"	CO, NO, NO ₂ , etc.
	Peerless (IR UV)	209	2-50,000	<5 sec	\$2800-\$3800	CO, NO ₂ , O ₂ , etc.
	Environmental Data	Diga-Series	"	"	"	NO, CO, CO ₂
	Wilks (IR)	Miran 5630	0.1-3000	30 sec	\$3950	CO, NO, NO ₂ , etc.
Correlation spectroscopy	Combustion Equipment (CEA)	Barringer	10-5000	20 sec	\$7800	None
Second-derivative spectroscopy	Spectrometrics	IV d ²	0.1 ppm-100%	Sec	\$9000	NO, NO ₂ , O ₂ , NH ₃ , etc.

* Information not available.

Another alternative would be to liquefy the coal sample and to then measure the sulfur content. Although possible, coal liquifaction is even more developmental than gasification and is therefore not considered feasible for the present study.

Nondestructive Analyses

The major advantage of nondestructive sulfur detection techniques is that little or no sample preparation is required. In addition, since the output typically counts individual atomic or nuclear events, rather than a macroscopic quantity related to the instantaneous sum of events, improvement in accuracy can be obtained by extending the counting time as opposed to increasing the event rate. Another advantage is that a relatively significant portion of the coal can be tested without its destruction in the analysis process. For these reasons, the techniques described in this section are considered to hold the most promise for large-scale sulfur analysis. Three available nondestructive techniques — neutron-induced gamma spectrometry, x-ray fluorescence, and Mössbauer spectrometry — are discussed below.

Prompt Neutron Activation Analysis--

Neutron-induced gamma spectrometry, which is also called prompt neutron activation analysis (PNAA), is based on the fact that when atomic nuclei absorb thermal neutrons, the activated nuclides often decay by promptly emitting gamma rays via the (n,γ) radiative capture reaction. Each nucleus emits a gamma ray having a characteristic energy which can be detected with scintillation material and electronically converted into a pulse having a voltage proportional to the incident gamma ray energy. These pulses can be separated according to voltage and counted. The number of counts attributable to any particular gamma ray energy can be related to the number of atoms of interest in the sample being irradiated.

Prompt neutron activation analysis has several attractive features. Investigators have demonstrated an accuracy of about $\pm 0.04\%$ in the measurement of total sulfur (compared to an accuracy of about $\pm 0.2\%$ sulfur attainable with ASTM methods) (Martin and Hall, 1976; Stewart et al., 1974; Herzerberg et al., 1978). A relatively large portion of the coal can be sampled in a fairly short time. For instance, one study (Martin and Hall, 1976) showed that 10 tons of coal per hour could be sampled at two-minute intervals (i.e., 30 two-minute counts could be made in one hour) using an 80 μg Cf²⁵² neutron source. Increasing the source strength would enable the counting period to be decreased further. Finally, because of the relatively low strength of the neutron source and the short time that the sample is exposed to the source, there is a negligible amount of induced radioactivity in the coal leaving the analyzer.

On the other hand, the presence of a neutron source and gamma ray emissions does require shielding and personnel monitoring. In addition to restrictions imposed on work performed in the area affected, there must be special precautions taken to ensure that the neutron source integrity is not violated by vibration or shock. Also, it should be noted that while PNAA appears technically feasible and attractive, there will be no data available from PNAA analyzers until mid-1980. In addition, the costs for such a device are unknown, although one proposed system has been estimated to cost \$200,000 to \$500,000, depending on the extent of the sample preparation equipment included (Kaiser, 1979).

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X-Ray Fluorescence--

In the nondispersive fluorescence technique, low energy x-rays (<10 Kev) irradiate the coal sample. Some of these x-rays are scattered inelastically (with relatively small decrease in energy) by atoms in the sample (Compton effect) but a large number lost all their energy by photoelectric absorption (i.e., ejecting an electron from an atom). When this occurs, the "hole" left by the photoelectron is filled by an electron from a higher energy level; however, the electron emits energy in the form of a "fluorescent" x-ray as it drops to the lower energy level shell. Fluorescent x-rays have energies characteristic of the atoms from which they are emitted and it is possible to select only the x-rays of a given energy for analysis. The intensity of the fluorescent x-rays is proportional to the concentration of sulfur atoms present.

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This principle has been applied in at least one sulfur analyzer (Horiba, 1977). Selectivity to sulfur is achieved by use of a filter, a narrow-range detector and a pulse-height discriminator circuit. The instrument has both a high speed mode (requiring approximately 40 seconds) in which the accuracy is $\pm 0.05\%$ and a low speed mode (requiring approximately 5 minutes) with an accuracy of $\pm 0.01\%$ sulfur. Internal shielding and the relatively low energy x-ray tube allow the use of the device without any special precautions.

The major disadvantages of the instrument are that only small quantities of coal can be analyzed (about 30 grams of finely ground coal per minute) and that interferences from other elements present as traces in the coal (notably Mo, Pb, and Bi) can have a serious effect on the sample results. The cost of this particular instrument for laboratory use is approximately \$10,000 (Horiba Instruments, 1977); larger commercial plant units would be considerably more expensive.

Because of the small sample size, the overall accuracy of this technique will be limited by the sample acquisition and preparation errors (as discussed in traditional coal analysis). Efforts to increase the size of the sample significantly will probably be unsuccessful since the low energy x-rays will be effectively attenuated in the material with a corresponding decrease in signal strength. However, it is possible that further development could result in a more practical x-ray fluorescent technique for continuous monitoring of coal sulfur on a larger scale than is currently available.

Mössbauer Spectrometry--

Mössbauer spectrometry is a specialized technique which involves the recoil-free emission and resonant absorption in solids of nuclear gamma rays. This is done by rotating the gamma ray source relative to the absorber and measuring the relative intensity of the gamma rays passing through the absorber (in this case, coal). This method has been used to detect specific forms of sulfur in coal that contain iron (i.e., pyrite, ferrous sulfate, etc) (Jacobs et al., 1978). Unfortunately, it is only sensitive to iron and thus is not readily adaptable to sulfur measurement. Therefore, this technique does not appear to be feasible for continuous monitoring of total sulfur.

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Evaluation of Techniques

Some of the instrumental methods previously discussed are considered to be too specialized or too developmental for use as a continuous sulfur meter. Mössbauer spectrometry and gasification or liquefaction of the coal sample prior to analysis are in this category. Instruments that measure SO_2 have the advantage of being commercially available; however, the need to oxidize the coal to SO_2 presents formidable problems in analyzing power plant feed stocks. Although a combustion system could probably be developed, its high cost (both capital and operating) coupled with the complex control that would be required to operate such a facility make this option unattractive compared to a technique such as prompt neutron activation analysis. Of the remaining two techniques, PNAA and x-ray fluorescence, the latter is commercially available but can only sample small (30 gram) samples of coal in its present form. Thus, it appears that prompt neutron activation analysis (PNAA) is the most promising technique for continuously monitoring power plant coal feed. This conclusion is based on the following feature of PNAA:

- Nondestructive analysis
- Rapid response time (≤ 2 minutes sampling period)
- High accuracy ($\pm 0.04\%$)
- Ability to sample large portion of coal stream (tons/hr)
- Feasibility of principle demonstrated

It should be noted that except for the unacceptably small sample size, x-ray fluorescence has many of the same attractive features of PNAA. If x-ray fluorescence can be developed to the point where significantly larger samples can be accommodated, this technique has one major advantage over PNAA: The low energy x-rays pose a much lower radiation hazard than the gamma rays of PNAA.

The following sections discuss the PNAA technique in more detail. Included is a review of the technique development and the state-of-the-art. Additional work required to transition the device to a commercial instrument is also presented.

6.4 PRINCIPLES OF PROMPT NEUTRON ACTIVATION ANALYSIS

Sulfur in its natural state consists of four stable isotopes having the following relative abundances:

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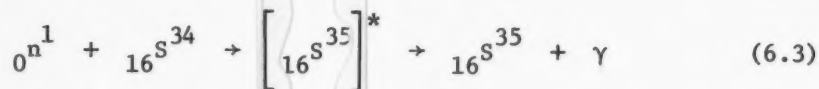
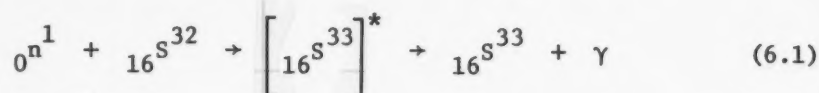
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Isotope	Atomic Weight (gm/gm-mole)	Relative Abundance (%)
$^{32}_{16}\text{S}$	31.972072	95.02
$^{33}_{16}\text{S}$	32.971459	0.75
$^{34}_{16}\text{S}$	33.9678677	4.21
$^{36}_{16}\text{S}$	35.967079	0.02

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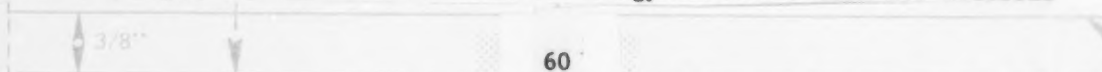
When exposed to a source of thermal neutrons, radiative capture (n, γ) occurs via the following reactions:



where $\left[\right]^*$ denotes the compound nucleus of the nuclide shown therein. The compound nucleus is in an excited energy state, having gained energy equal to the binding energy of the neutron plus its kinetic energy, and exists on the order of 10^{-14} second prior to de-excitation by emitting a γ -ray. The majority of the thermal neutron capture γ -emissions are produced as the result of Equation 6.1.

Capture gamma rays are emitted with discrete energy levels. The predominant γ -ray energies for sulfur are listed in Table 8. The reason only discrete energies are emitted is because the capture excitation energy in the nucleus is shared by all the nucleons, which can only exist at specific energy levels. Thus, the only γ -rays that can be emitted correspond to the difference between any two energy levels. This also explains why different elements (and different isotopes) emit γ -rays of characteristic energies: As the number of nucleons (i.e., neutrons and protons) changes, so do their energy levels and thus their emission spectra. Also shown in Table 8 are the number of photons (i.e., γ -rays) emitted as a function of energy level for each 100 neutrons

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absorbed by sulfur nuclei. Thus, on the average, 42.44 photons are emitted at 5.420 Mev for each 100 neutrons captured; 19.46 photons emitted at 3.221 Mev for each 100 neutrons captured; and so on. It should be noted that no photons having energies less than 3 Mev are shown in the table, although a significant number of these "soft" gammas are produced. They are not easily distinguished from photons produced by other elements in coal and thus are not particularly useful in the PNAA techniques.

TABLE 8. THERMAL NEUTRON RADIATIVE CAPTURE γ -RAY (> 3 Mev) OF NATURAL SULFUR (Duffey et al., 1970)

Energy (Mev)	Intensity (photons/100 neutrons)
8.641	1.91
7.800	2.81
5.420	42.44
5.047	2.26
4.870	8.24
4.639	1.49
4.431	3.16
3.723	2.03
3.370	3.78
3.221	19.46

While capture γ -rays of Table 8 are being emitted for sulfur, neutrons absorbed by other elements in coal result in γ -emissions having energies characteristic of those elements. Unfortunately, many of the photons emitted from the elements of coal are very close in energy and care must be taken to distinguish the source of a particular photon. In addition, secondary photons are produced as primary photons are attenuated (i.e., absorbed) in the various materials present in a PNAA installation. These secondary photons are produced when a primary photon of energy greater than 1.02 Mev is attenuated via the pair production process. In pair production, an incident gamma ray disappears in the vicinity of a nucleus and an electron (β^- particle) and a positron (β^+ particle) are produced as depicted in Figure 31. These particles then lose energy by excitation and ionization of bound electrons in the absorber material. When the positron loses its kinetic energy, it combines with an electron to form two 0.51 Mev secondary photons (the total, 1.02 Mev, being the rest mass of an electron-positron pair).

These secondary photons complicate the PNAA emission spectra of coal when they are produced in the photon detector itself. If pair production occurs and both of the 0.51 Mev photons are absorbed in the detector, the total energy

of the primary photon is detected. However, if one or both of the secondary photons escape from the detector, it senses a total energy 0.51 or 1.02 Mev less than the primary photon energy. Thus, for the 5.42 Mev primary photon of Table 8, a single photon escape will result in $5.42 - 0.51 = 4.91$ Mev being detected while both photons escaping will result in $5.42 - 1.02 = 4.40$ Mev appearing in the detector. Therefore, some of the photons resulting from sulfur capture may appear at energies close to the emission energies of other elements, and vice versa. In order to compensate for these effects, analytical techniques such as linear combination and spectrum stripping methods must be employed to accurately account for the source of the photons. One such method will be described in the next section.

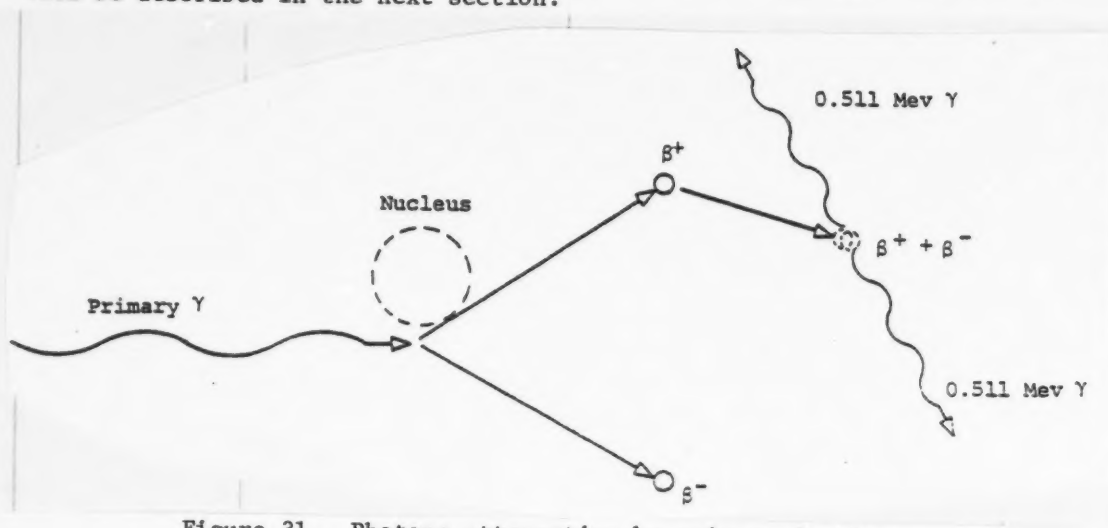


Figure 31. Photons attenuation by pair production.

While radiative capture is a possible reaction following absorption of a neutron by a nucleus, it is by no means the only reaction possible and may not even be the most probable. The compound nucleus may emit a neutron having the same energy as the incident neutron, which is called elastic scattering (n,n) since there is no discernible difference between the incident and ejected neutrons. On the other hand, if a neutron is emitted with an energy lower than the incident neutron, the process is called inelastic scattering (n,n'). These scattering processes are shown in Figure 32. Other particles may be emitted, such as a proton (n,p) or an alpha particle (n,α). As noted previously, when a neutron is absorbed in a nucleus, the binding and kinetic energy of the neutron is shared among the other nucleons, and the emission of a nucleon is delayed until one nucleon attains an energy greater than the binding energy via collisions with other nucleons. It would be expected, then, that a nucleus containing a large number of nucleons would take longer, on the average, for a nucleon to attain sufficient energy to be emitted. If nucleon emission is delayed by much more than about 10^{-14} second, the average time for γ-ray emission, the compound nucleus will probably decay by emitting a γ-ray. Thus, it would be expected that heavier nuclei (which have more nucleons) would tend to decay via γ-ray emission, while lighter nuclei, such as the majority of the elements found in coal, would tend to decay by emission of a nucleon.

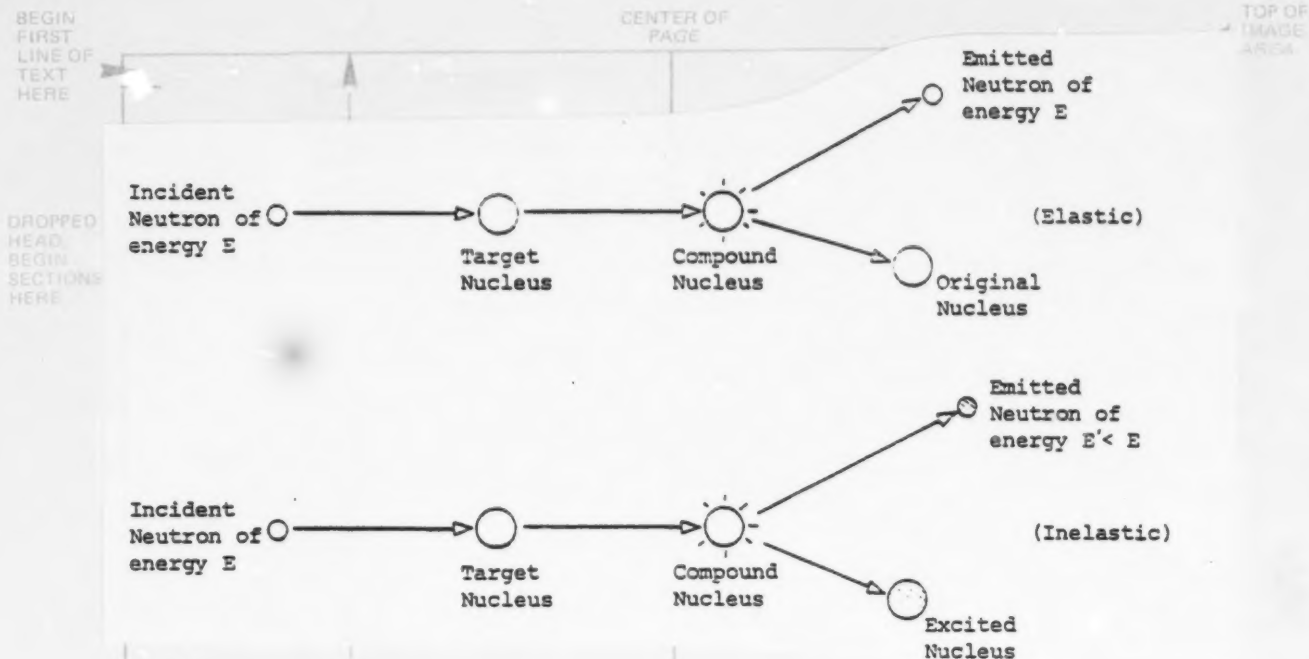


Figure 32. Neutron scattering.

It turns out, in fact, that the lighter elements, (elements having an atomic number ≤ 25) do indeed generally decay by nucleon emission. A neutron is usually emitted so that the overall effect is neutron-scattering, i.e., a (n,n) or (n,n') reaction. For this reason light elements are very good moderators of fast neutrons; energetic neutrons are slowed down to the point where they are in thermal equilibrium with the moderating material. Although neutron scattering may be more probable, radiative capture is usually a significant process, however. Thus, for a large number of incident neutrons, there may be a very significant number of capture γ -rays produced, even if radiative capture is not the most probable reaction. This, of course, is the case when coal is exposed to a source of neutrons in the PNAA technique.

Thus far, no mention has been made of the source of neutrons for inducing radiative capture in coal. The exact source is in reality relatively unimportant (although Californium-252 has become the source of choice for PNAA) as long as it has sufficient strength to cause a statistically significant number of capture gamma rays to be detected. Also, whether a fast (energetic) or slow thermal neutron results in radiative capture is not important for the same reason. Therefore, the phenomena of neutron slowing down, of nuclide cross sections (the probability of a neutron being absorbed) and their energy dependence, and of cross section resonances are beyond the scope of the work and will not be discussed here. Also, as explained in the next section, the use of a difference technique can effectively eliminate variations in the sulfur measurement due to the phenomena listed above.

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6.5 APPLICATION OF PROMPT NEUTRON ACTIVATION ANALYSIS

When coal is exposed to a neutron source, a spectrum of radiative capture photons is produced from the various elements contained in the coal. To measure the relative abundance of sulfur (or any specific element), it is necessary to differentiate the photons emitted from sulfur from those of the other elements. This is generally accomplished using electronic discriminator circuits.

The photons produced in radiative capture can be detected in a scintillation detector, where absorption of the photons produces bursts of visible light whose intensities are proportional to the incident photon energies. There are several different types of scintillators, the most common being thallium-doped, sodium iodide [NaI(Tl)] crystals. The visible photons produced in the scintillator are conducted (often by means of a light pipe) to a photomultiplier tube, where photoelectrons are generated and then amplified through the process of electron multiplication. The electronic pulses from the photomultiplier tube have voltages (i.e., pulse heights) proportional to the incident gamma rays energies. Discriminator circuits are then used to separate the pulses according to pulse height. When coupled according to pulse height, a gamma spectrum such as the one shown in Figure 33 is obtained. This particular spectrum was obtained using an 80-microgram Californium-252 neutron source and a 6- by 7-inch NaI(Tl) detector. The number of counts in the 5.43 Mev sulfur peak is an indication of the sulfur content of the coal.

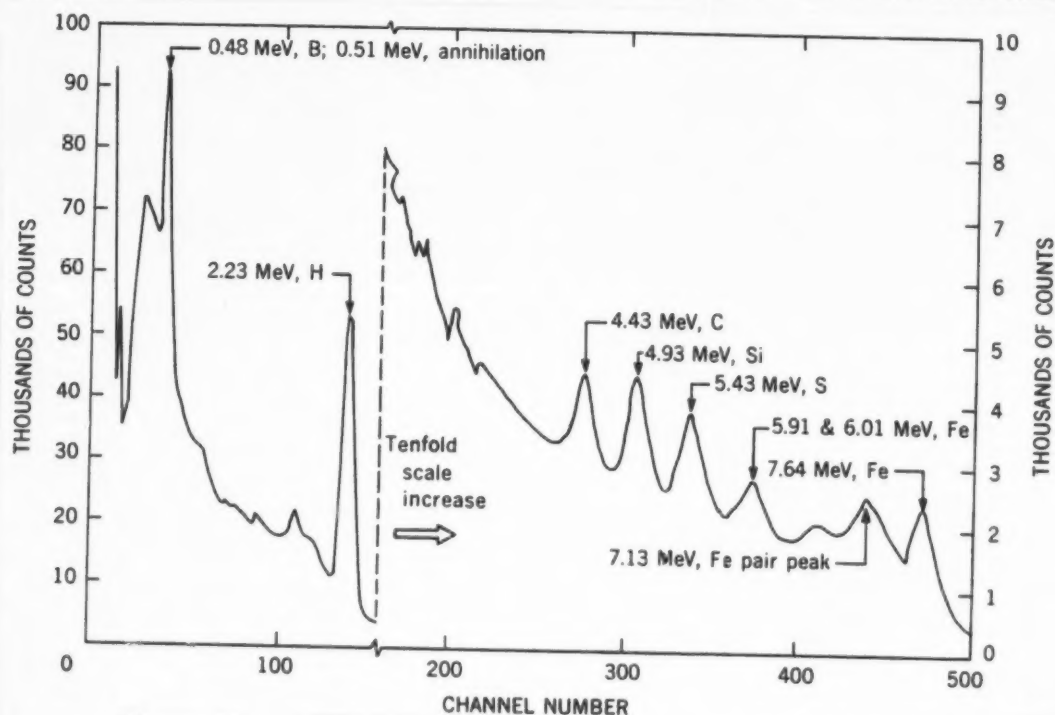


Figure 33. Gamma ray spectrum of coal measured with a Cf-252 source and 6- by 7-inch NaI(Tl) detector. (Stewart, 1974)

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Unfortunately, the number of counts in the 5.43 Mev peak is not an accurate measure of the sulfur level. One reason for this is the production of secondary photons in the detector as the result of pair production (discussed in the previous section). Thus, some of the 5.43 Mev photons actually appear at 4.92 Mev (single escape peak) and others at 4.41 Mev (double escape peak) while secondary photons from other elements appear in the 5.43 Mev peak. A second reason the 5.43 Mev peak should not be used by itself for sulfur measurement is that the number of counts will vary as certain conditions change. For instance, variations in coal density and moisture content will affect both the slowing down of neutrons from the source and the degree of attenuation of photons produced in radiative capture, which will in turn affect the number of photons reaching the detector. In addition, the natural decay of the neutron source will also cause the source strength to vary as a function of time.

The last three effects can be compensated for by measuring the magnitude of the 5.43 Mev sulfur peak relative to some other portion of the spectrum. One investigation employed two single channel analyzers to measure the total counts in areas A and B shown in Figure 33 and to automatically display the difference between the two areas. Since counting continued until about 2×10^6 counts were accumulated in the primary spectrum region (area A), variations in the photon emission rate due to changes in coal density, moisture and source strength appeared in both channels and were automatically eliminated in the differencing technique. Of course, these variations did alter the length of time that it took to accumulate the predetermined number of counts in channel A. This difference technique can be used to partially compensate for secondary photons in the spectrum; however, only a relatively few of the interfering elements can be considered. In a later study (J.W. Martin, and A.W. Hall, 1976), the difference technique was revised (based on a theoretical analysis which considered all of the major elements in coal) to automatically display the quantity $[C-D/2]$ (i.e., the difference in counts between areas C and D) shown in Figure 33. This method better accounted for the secondary energy peaks, since it considered the source of all photons contributions within ± 0.2 Mev of each of the peaks used (4.43, 4.93, 5.43, and 6.01 Mev).

Although this detection and analysis system has been shown to work on a pilot scale (as described in the next section), it has yet to be proven practical on a demonstration plant due to coal sample handling problems. Whereas NaI(Tl) scintillation crystals are efficient and are widely used in laboratory setups, the effect of typical coal power plant environment on the device is unknown. It must be able to withstand vibration, shock, heat and coal dust. NaI crystals must be hermetically sealed since they are highly hygroscopic and are subject to mechanical failure. All detectors must be protected from extraneous light sources to ensure that only light sources indicative of gamma induced scintillations are counted. In addition, good physical contact must be maintained between the detector and the light pipe and/or photomultiplier tube. Detectors other than NaI can be used but each have their own characteristic disadvantages. Semiconductor detectors eliminate the need for a photomultiplier tube since the incident photons are directly converted to electrical pulses. Germanium-lithium (GeLi) detectors, for instance, have better resolution than NaI crystals but are less efficient and require cryogenic cooling.

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Other parts of the detection system are also susceptible to the plant environment. Besides the electronic equipment itself, such as power supplies, amplifiers, and pulse discriminator and shaping circuits, which must be temperature-controlled and protected from shock and vibration, interconnecting cables must be shielded to prevent extraneous signals and are susceptible to dust and foreign materials if poor connections exist or develop at the terminals.

One of the most important operational aspects of the PNAA technique lies in shielding the neutron source. The presence of a radioactive neutron source requires that shielding and special practices be employed to ensure that personnel are not exposed to an unacceptably high level of radiation. To minimize personnel exposure, as small a source as possible is desired. However, the source must also be large enough to ensure a statistically significant sample is obtained in a reasonable length of time. A related factor is the amount of coal that is to be sampled, as well as the geometry of the coal feed (i.e., horizontal belt, vertical bin, etc.).

The presence of a neutron source may require licensing requirements (depending on the source type and individual state regulations) and will require periodic surveys and reports. Instrument servicing will necessitate a technician trained in handling and working with radioactive materials. The source integrity must also be considered, again in light of the severe environment of a coal plant. Also, since neutron sources have finite half-lives, source replacement will be necessary when the source strength decays to a predetermined level.

Another problem to be considered with the PNAA technique is the manner in which the device is periodically calibrated. The reliability of the system should be analyzed and the need for redundant components identified. Finally, instrument design must accommodate possible sources of sulfur not contained in the coal, since any such source could render the PNAA instrument inaccurate.

6.6 DEVELOPMENT OF PROMPT NEUTRON ACTIVATION ANALYSIS

Much of the early development of prompt neutron activation analysis for coal sulfur was done at Morgantown Energy Research Center (MERC) in Morgantown, W. Va. The possibility of using PNAA in a continuous mode was first reported by Stewart et al., in 1974. In that series of tests, coal was recycled through the test bin at flow rates up to 50 tons per hour in a simulated industrial system shown in Figure 34. An 80-microgram Californium-252 (Cf^{252}) neutron source was positioned in the center of the 1-meter diameter cylindrical bin. Cf^{252} is a source of low-energy (average energy - 2.15 Mev) fast neutrons that are easily slowed down and thermalized by the light elements, (carbon and hydrogen) contained in coal. The resulting gamma radiation was then detected in a 6- by 7-inch, thallium-doped, sodium iodide crystal. An accuracy of $\pm 0.04\%$ in the sulfur measurement was obtained.

The successful development of the PNAA technique at MERC led to a full scale test in the Robena Coal Preparation Plant of the U.S. Steel Corporation

in southwestern Pennsylvania (Hall et al., 1975). The plant configuration is shown in Figure 35; the actual PNAA installation was as previously described. Results confirmed the sulfur measuring accuracy at $\pm 0.05\%$ for two-minute counting, 20-second readout intervals. Comparison with ASTM chemical analysis was excellent with a difference range of $\pm 0.09\%$. However, mechanical problems plagued the coal handling system and plugging problems in the test bin led to irregular flows and shutdowns of the PNAA system.

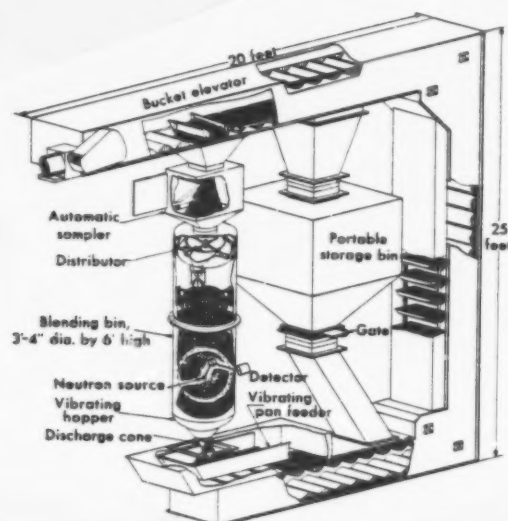


Figure 34. Schematic of coal recycle system.
(Stewart, 1974)

The Electric Power Research Institute (EPRI) through its contractors, Science Applications, Inc., and Kennedy Van Saun Corporation, has been conducting a program for development of a PNAA coal monitor since 1976. This program called CONAC (Continuous On-line Nuclear Analyzer of Coal), has the following objectives (Science, 1979):

- Control coal quality at the mine
- Provide surveillance for coal in storage areas
- Process control at coal preparation and conversion plants
- Provide for total heat management of a utility power station
- Predict and avoid boiler slagging or fouling episodes in utility boilers
- Meet SO_2 and particulate emission regulations more effectively
- Provide the means to schedule and optimize power system load flow more efficiently

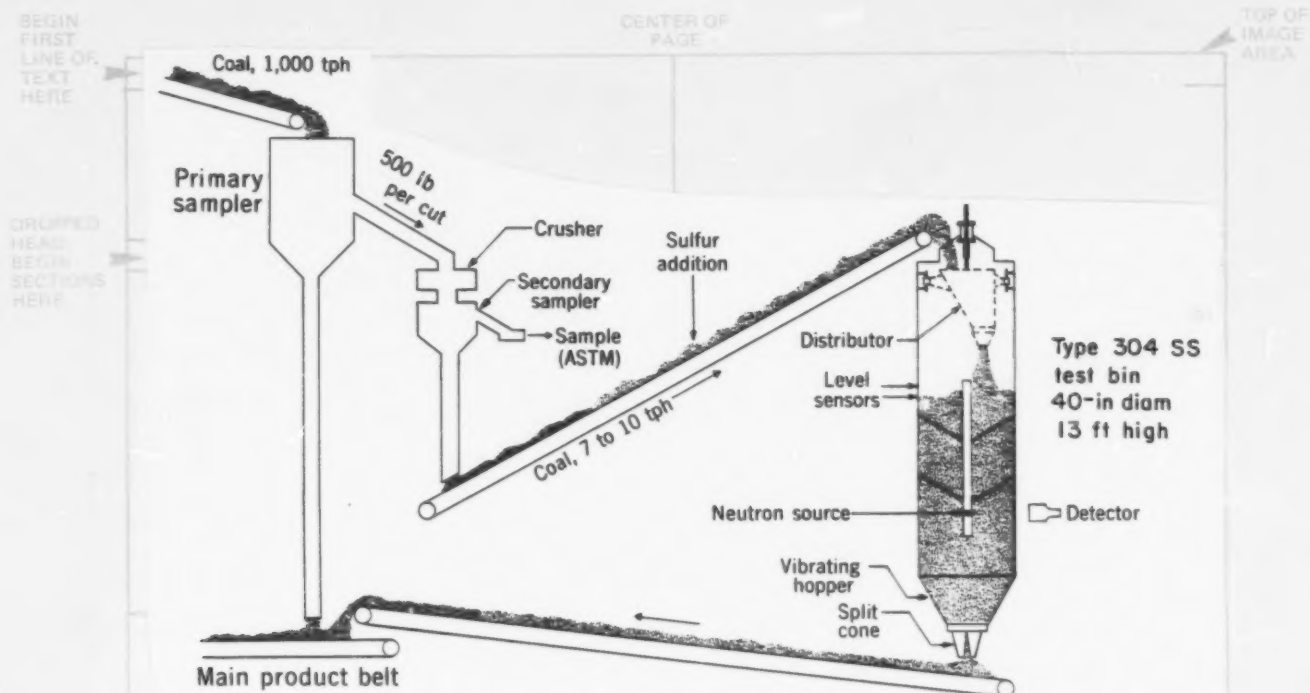


Figure 35. Schematic diagram of meter installation at coal preparation plant. (Hall, et al., 1975)

The data output of CONAC will consist of:

- Percentage of sulfur by weight
- Percentage of moisture by weight
- Calorific value of coal (Btu/lb)
- Percentage of ash by weight
- Principal elements in ash

Work to date has consisted of a review and analysis of the various techniques that will be required in the CONAC system and of preparations to construct and test a utility scale prototype (Kaiser, 1979; Science, 1979a; Science, 1979b; Kennedy and Science, 1979a; Kennedy and Science, 1979b; Kennedy and Science, 1979c). This final phase of the program is expected to be completed in 1980.

A conceptual schematic of the CONAC equipment arrangement is shown in Figure 36. The CONAC system employs a belt feeder rather than a bin arrangement (as was used in the Morgantown experiments) to prevent segregation of the coal (Kennedy and Science, 1979c). Also, a nuclear mass flow meter is to be used which consists of a source of gamma rays (a Cs^{137} source) and a gamma detector (Kennedy and Science, 1979b). In the PNAA analyzer shown in Figure 36, a germanium-lithium detector (GeLi) is used rather than a NaI crystal because the former has better resolution for the elemental ash analysis.

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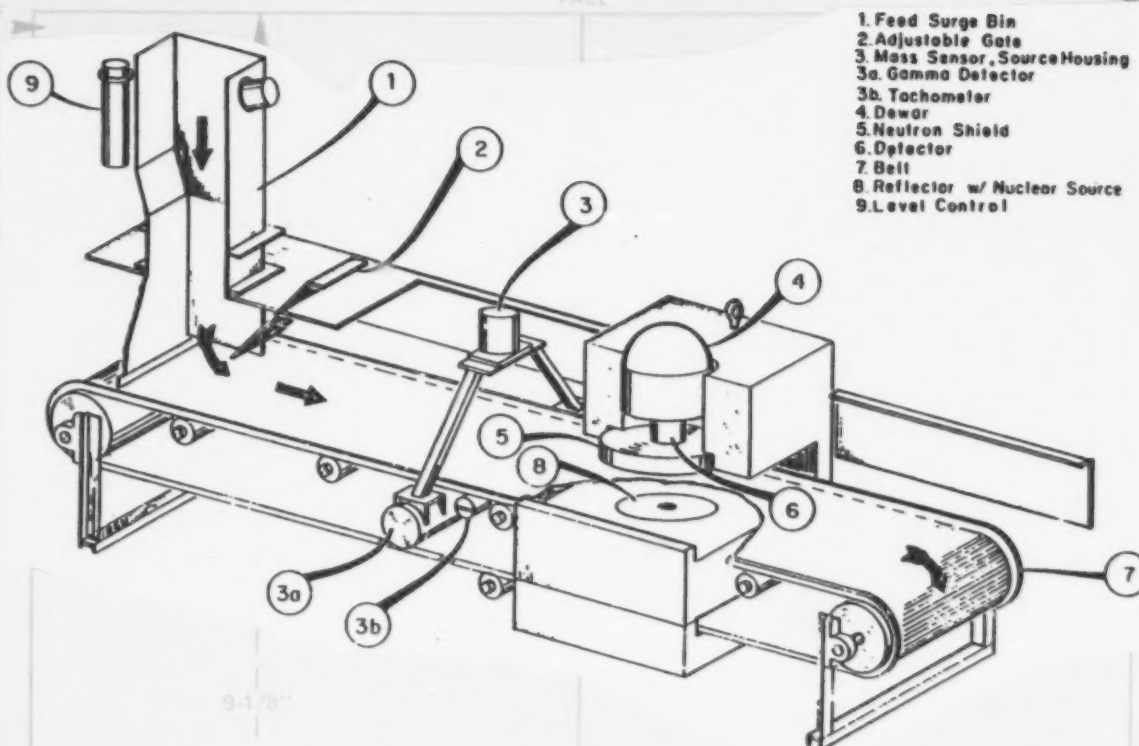


Figure 36. Conceptual CONAC. (Kaiser, 1979)

The potential speed and accuracy of PNAA for analysis of trace elements in the fuel, sorbent and solid wastes associated with coal combustion is promising. A possible integration of the CONAC system into a power plant coal handling system is depicted in Figure 37. A simplified version of CONAC suitable for rapid coal sulfur analysis only is presented in Figure 38. In this case, a NaI crystal detector is used for the PNAA analyzer because it has a higher efficiency than the GeLi detector and does not require the high resolution needed for elemental analysis.

Actual data on the accuracy and reliability of the CONAC system will not become available until the prototype becomes operational. However, Table 9 does present a comparison of the results obtained for the PNAA analysis and the ASTM analysis for the concentrations of hydrogen, sulfur, carbon, and chlorine in various coal types. The results for sulfur have been correlated in Figure 39.

In the figure, points falling on the straight line correspond to perfect agreement between the sulfur meter results and the ASTM technique results. As can be seen, there is very good agreement between the PNAA and ASTM techniques.

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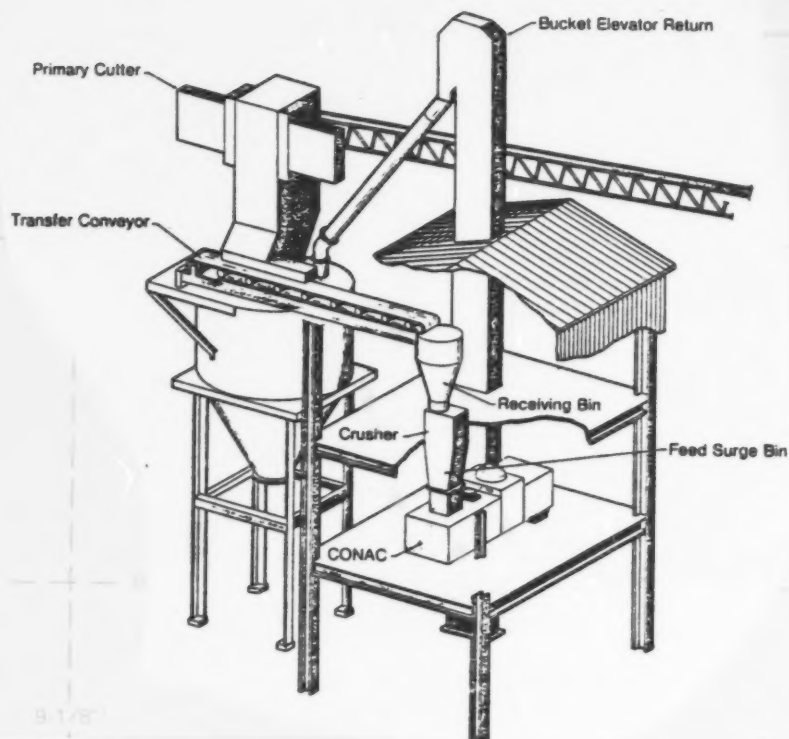


Figure 37. CONAC integrated into a typical power plant.
(Kaiser, 1979)

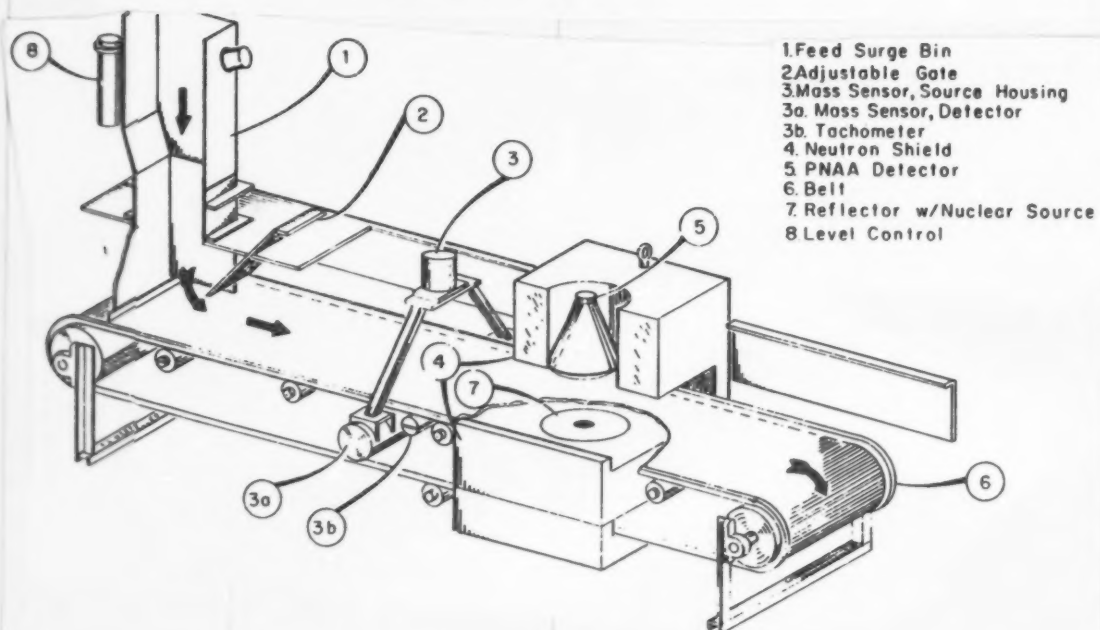


Figure 38. Sulfurmeter. (Kaiser, 1979)

TABLE 9. CONCENTRATION OF SOME ELEMENTS IN VARIOUS TYPES OF COAL AS DETERMINED BY CONAC AND CONVENTIONAL ASTM TECHNIQUES (Kaiser, 1979)

COAL TYPE	ANALYSIS ("As Received" Basis)							
	HYDROGEN		SULFUR		CARBON		CHLORINE	
	PNAAT	ASTM*	PNAAT	ASTM*	PNAAT	ASTM*	PNAAT	ASTM*
E. Ohio (14)	5.11 ± .02	5.02 ± 0.11	2.91 ± .02	2.91 ± .13	68.65 ± .9	68.7 ± 1.3	0.123 ± .002	0.086
DEK	5.44 ± .02	5.23 ± 0.99	0.38 ± .01	0.39 ± .07	56.36 ± .7	60.5 ± 5.2	0.0038 ± .0006	0.018
E. KEN.	5.62 ± .02	4.93 ± 0.19	0.90 ± .01	0.82 ± .04	69.11 ± .9	67.8 ± .1	0.039 ± .001	0.037
B1	5.74 ± .02	5.52 ± 0.64	1.25 ± .01	1.28 ± .17	63.77 ± .8	67.8 ± 4.4	0.051 ± .001	0.042 ± .018
B2	6.03 ± .02	5.63 ± 0.98	1.34 ± .01	1.21 ± .09	65.16 ± .8	64.9 ± 4.4	0.050 ± .001	0.086 ± 0.034
NH (4)	4.78 ± .02	4.70 ± 0.53	0.93 ± .01	0.94 ± .03	51.50 ± .7	55.8 ± 4.0	0.066 ± .001	0.082
PITTS.	5.13 ± .02	5.13 ± 0.07	2.91 ± .02	2.91 ± .03	71.40 ± .9	71.4 ± .7	0.145 ± .001	0.144 ± 0.023

*PNAAT uncertainties in analysis

PNAAT = Prompt Neutron Activation Analysis.

*ASTM uncertainties based on deviations between 2 or 3 laboratory results. With Chlorine where no uncertainties are quoted, only one laboratory submitted results.

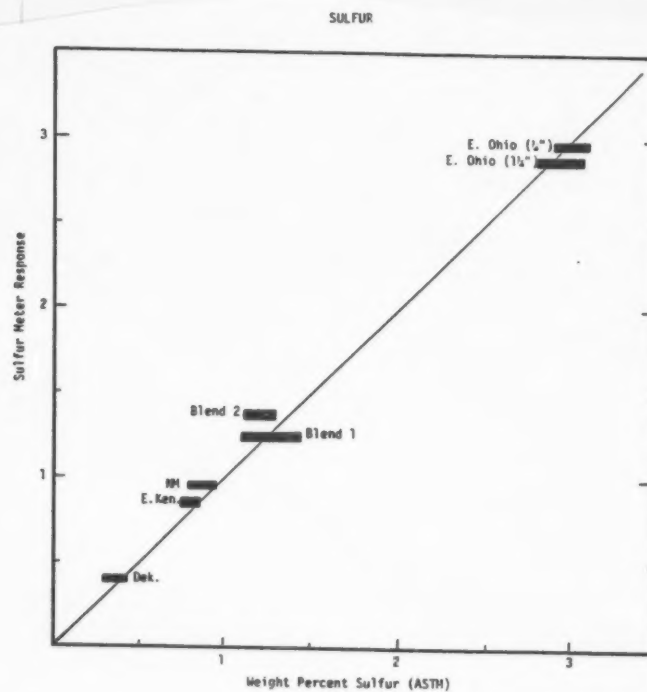


Figure 39. Weight percent sulfur determined from sulfur meter response plotted against ASTM results. The uncertainties in ASTM show the range in weight percent sulfur determined by the two laboratories. (Kaiser, 1979)

Argonne National Laboratory (ANL) has an ongoing program to develop instrumentation for advanced coal utilization processes. They are investigating the use of PNAA for on-line analysis of coal stream elemental composition (Herzerberg et al., 1978), and have developed a largely automatic unit for analyzing the contents of a 30 centimeter pipe. Their arrangement, which is directed more toward coal slurries than bulk coal, is expected to give read-outs every 20 minutes at 0.1% accuracy and be amenable to commercialization.

The Technology for Energy Corporation has submitted a proposal to the Tennessee Valley Authority for a PNAA system that could be used for rapid sulfur testing of truck and railcar lots of coal (Technology, 1978). They also plan to investigate Cf²⁵² source strength, detector type and configurations, reducing the impact of dust, vibration and heat on the equipment, and optimizing the electronic signal analysis.

A number of organizations have determined that prompt neutron activation analysis holds definite promise for monitoring coal sulfur (as well as other coal elements) on a continuous basis, and therefore warrants further development. Efforts to date have demonstrated the technique to be a viable concept; what remains to be done is to construct and test a utility scale prototype, to modify the design based on the results of the test, and then to build and market the device as a commercial product. Based on the present and planned activities of EPRI (and its subcontractors), MERC, ANL, and the Technology for Energy Corporation, as noted above, the current and planned developmental efforts appear adequate.

6.7 SUMMARY

Due to the nonhomogeneous nature of coal, the accuracy of the sulfur measurement is improved by sampling a larger percentage of the coal and analyzing a significant portion of the coal stream. Nondestructive analysis of the coal sulfur content is more desirable than destructive analysis for testing a larger percentage of a given coal stream, since the destructive means becomes prohibitively expensive and wasteful. However, if sampling techniques can be developed that provide a small representative sample of the coal being fed, several of the destructive techniques would be acceptable.

Although still under development, prompt neutron activation analysis has been determined to be the most promising instrumental technique for measuring sulfur on an essentially continuous basis. The technique offers the advantage of nondestructive analysis, rapid response time, high accuracy and ability to sample a large portion of the coal stream.

A practical PNAA device requires additional development to integrate the instrument into a coal feed system as much as it requires further development of the instrument itself. One major effort will be to prove the ruggedness of the PNAA device in the harsh environment of a typical coal power plant. Other problems to be addressed include the manner in which the coal is presented to the PNAA monitor, the means of providing radiation shielding, and the method by which the system is calibrated.

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Current and planned developmental efforts at METC, EPRI, ANL, and private industry appear adequate at this time to fabricate and test a PNAA sulfur monitor. The EPA should monitor these activities to establish the viability of the PNAA instrument and to determine its effectiveness as a tool to demonstrate compliance with government sulfur emission standards.

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7.1 EXPECTED VARIATIONS IN COAL SULFUR CONTENT

This section describes the expected variations in coal sulfur content and the preferred method of measurement of sulfur retention. It then discusses the technical aspects of four different methods for controlling the absorption properties of the bed. The conclusion of this section is an economic comparison of the preferred concepts and a detailed description of the preferred control system.

Little data exists in the open literature on the natural variations in coal sulfur content. Variations within a particular seam of coal are usually small. However, coals from various seams are easily mixed and can cause large variations in the sulfur content. Table 10 shows the range of the daily sulfur content for a 40-MWe coal plant firing high sulfur coal for four months and low sulfur coal for five months (LaMantia et al., 1977). The high sulfur coal shows a maximum upward excursion of 46% from the average and the low sulfur coal data shows a maximum upward excursion of 40% from the average. Figures included in this reference show the excursions lasting 2 to 3 days. If this data is put on a comparable basis for a 660-MWe PFB plant, the excursion period would last 3 to 4.5 hours.

TABLE 10. RANGE OF SULFUR VARIATION FOR A 40-MWe POWER PLANT (LaMantia et al., 1977)

	Range	Average
Low Sulfur Coal		
Sulfur (wt %)	0.9 - 2.2	1.6
HHU (J/gm) (Btu/lb)	$26.7 \times 10^3 - 30.2 \times 10^6$ (11,500 - 13,000)	27.9×10^3 (12,000)
High Sulfur Coal		
Sulfur (wt %)	2.4 - 5.1	3.5
HHU (J/gm) (Btu/lb)	$23.3 \times 10^6 - 30.7 \times 10^6$ (10,000 - 13,200)	28.4×10^6 (12,200)

Meyer (1979) has studied changes in the distribution of sulfur in coal as it undergoes mining and transport operations. The base case data used in his analysis had a mean sulfur content of 0.53 and a standard deviation of 0.17. No information was given about the duration of transients.

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Because of the scant amount of data available on the range and duration of natural variations in coal sulfur content, incremental costs for the preferred control concepts are determined as a function of the size and duration of the excursion in sulfur content.

7.2 MEASUREMENT OF RETENTION

To maintain constant retention on an instantaneous basis in a fluidized bed power plant the retention of the bed must be continuously measured. Conventional scrubber plants determine instantaneous sulfur capture by measuring the amount of sulfur in the flue gas before and after the scrubber module. Consequently, control of the absorption system can be performed using only flue gas monitors.

Sulfur leaving a fluidized bed can be measured using normal flue gas techniques, but sulfur entering the bed requires special equipment. The various methods of measuring sulfur input to the fluidized bed are reviewed in Section 6 of this report. That review concludes that prompt neutron activation analysis (PNAA) of the coal feed into the bed is the preferred method for this task.

As an alternate to measuring the total amount of sulfur entering the bed using continuous PNAA, the total amount of sulfur leaving the bed by all methods can be measured. This would require that the utilization of all particles leaving the bed via offtake and elutriation be determined. There is no way to do this accurately without unacceptable delay. Consequently, this method was rejected in favor of PNAA.

In the following discussion, the use of the PNAA meter is discussed assuming that such meters are commercially available for use in fluidized bed boiler plants and can operate reliably over extended periods in such applications. As indicated in Section 6, such meters are still under test, and have not yet been demonstrated in extended commercial operations.

Recommended PNAA Installation Location

The PNAA meter can be incorporated into the PFB power plant coal feed system in two places. The location of addition can be seen on Figure 40.

The first place where the PNAA meter could be added is parallel to prepared coal conveyor (CR-90-12 A/B). A small portion of the coal feed stream on this conveyor would be diverted to a separate conveyor on which the PNAA instrument would be installed. After measurement, the coal would be discharged onto prepared coal conveyor (CR-90-13). There are two parallel coal feed streams at this location. Consequently, two PNAA meters would be required if installed at this location. This option has several technical problems which must be resolved before it can be used in the plant.

There are two storage bins between the point of sulfur content measurement and the feed point to PFB. These bins represent a delay of 24 hours and approximately 4 hours. Feeding and emptying these bins will result in non-uniform mixing of coal, which will change the variations in coal sulfur content. To make this concept viable, expressions must be determined that relate the sulfur content measurement at conveyor (CR-90-12 A/B) to the rate of sulfur fed to the bed.

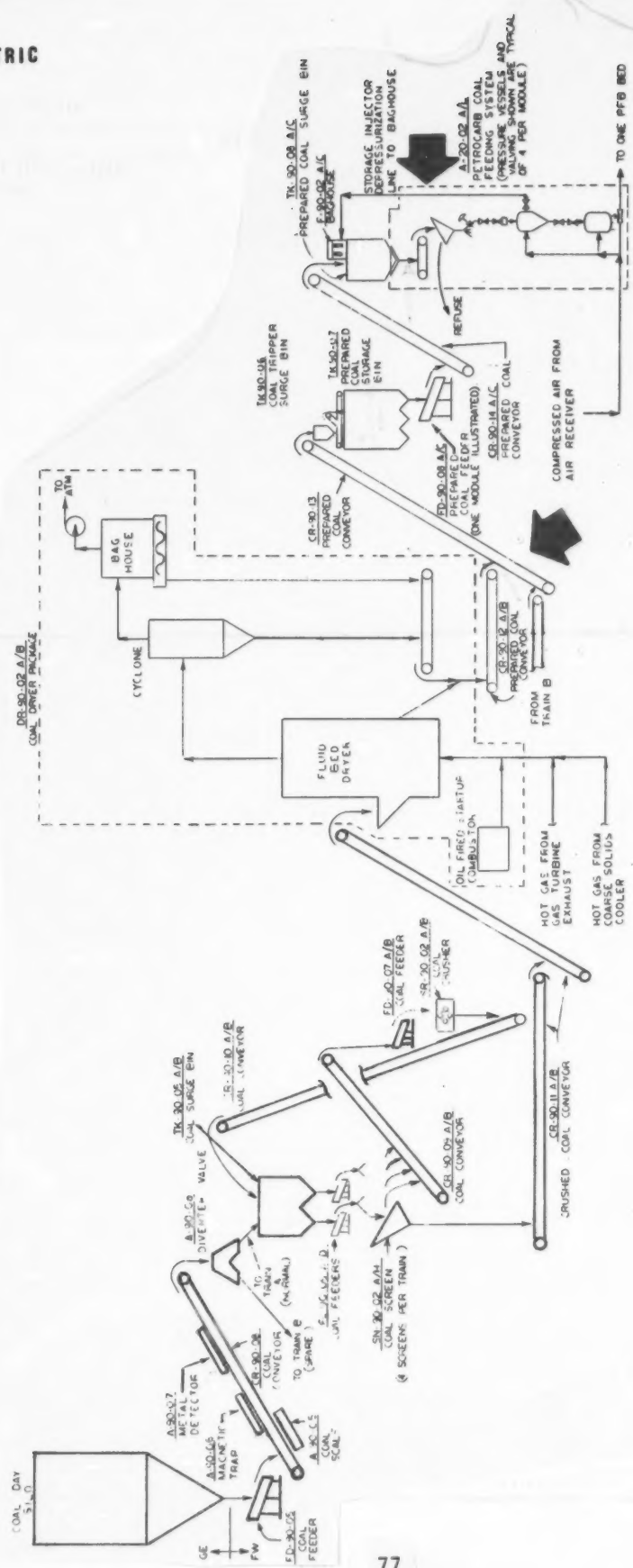


Figure 40. Coal Feed System

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The second place where the PNAA meter could be added is on the conveyor below the prepared coal surge bin (TK-90-08 A/C). There are six parallel coal feed streams at this location. Therefore, six PNAA meters would be required. There are no foreseeable technical problems with this location of installation.

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Both installation locations described above are considered in the following economic analysis.

7.3 METHODS OF CONTROL

Four candidate approaches to control bed retention were identified and evaluated:

1. Changing the size distribution of the dolomite feed
2. Feeding dolomite of higher reactivity
3. Adjusting dolomite feed rate
4. Blending high sulfur coal with low sulfur fuel such as low sulfur coal, SRC, natural gas, or oil

The following discussion explains the advantages and disadvantages of each of these systems. Control actions 3 and 4 were both found to be technically viable. Also discussed is the normal method of insuring compliance with emission standards (no control scenario).

Changing the Dolomite Feed Size Distribution

Decreasing the feed size distribution will increase the rate that sulfur will be absorbed by the bed. The reason for this is that the rate of the sulfation reaction is larger for smaller size particles and they are capable of reaching higher utilizations.

Ideally, this system of maintaining high retention would have a constant dolomite feed regardless of coal sulfur content. As the coal sulfur content increased the Ca/S ratio would decrease. Under normal conditions the retention would decrease, but by adding smaller particles to the bed the reactivity and sulfur retention will remain constant. If this is true, the average particle utilization must also rise. For example, a bed operating at a Ca/S ratio of 1.5 and a 90% sulfur retention would have an average utilization of 60%. If the coal sulfur content increased by 50%, the average utilization would need to rise to 90% to maintain 90% sulfur retention within the bed. It is unlikely that this high utilization could be attained without serious problems of particle elutriation.

The feed particle size distribution may be limited by elutriation. If the size distribution were reduced, the amount of elutriated material would increase. The increased amount of elutriated material would be fresh material recently added to the bed. This would result in inefficient use of dolomite unless recycle equipment were added to the system.

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This system alone probably could not increase the reactivity enough to control excursions of 50% in the coal sulfur content. If so, this system must be used in conjunction with one of the other systems. The combination results in a complex control system that requires a combination of control actions.

In addition to the above, it will be difficult to control the rate at which this system returns to steady state. Once the bed population distribution is perturbed by the addition of small particles, the rate at which the system returns to normal operation is not controllable. It is determined by the sink terms of the population distribution equation (elutriation, offtake, rate of change in utilization). Inefficient use of dolomite could result.

The response of retention to this control action is rather slow. Figure 41 shows the change in retention, average utilization and average bed particle size for a decrease in feed particle size distribution. The sizes of the feed distribution shown in Table 5 were multiplied by a factor of 0.66. Note the long time required to effect a change in the average bed particle size, primarily because the inventory of the bed is large compared to the dolomite feed rate.

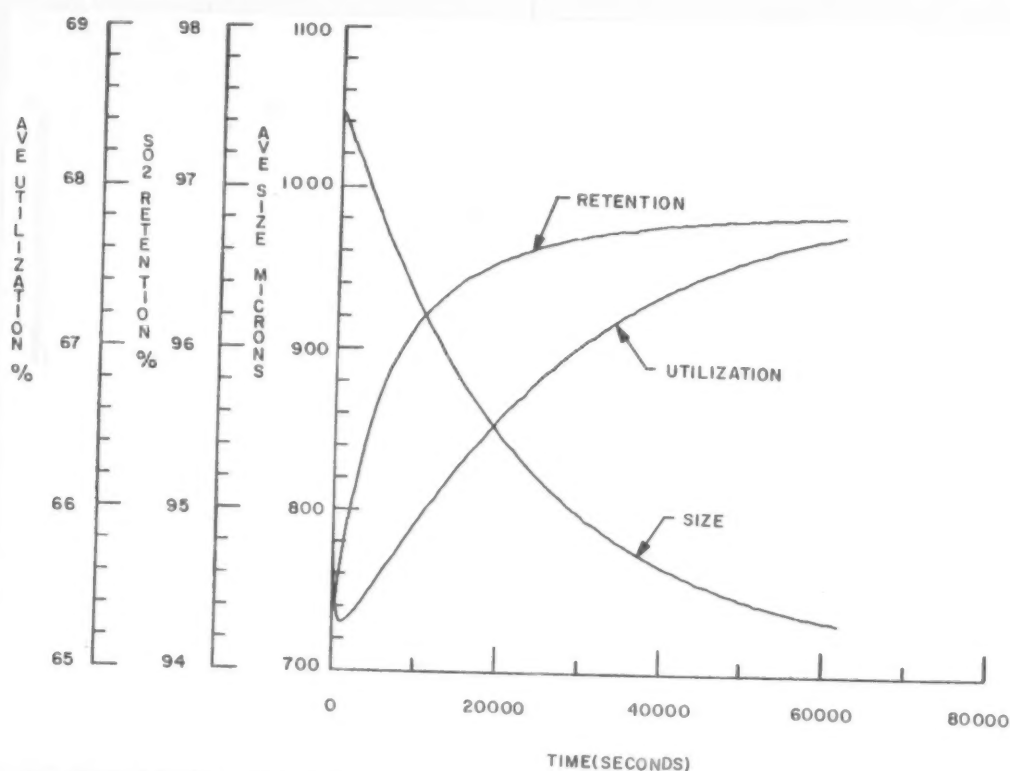


Figure 41. Changes in retention, average utilization and average bed size particle following a step decrease in the dolomite feed size distribution.

In addition, this control action would not take advantage of downward excursions in sulfur feed rate.

This control action has several disadvantages and no clear advantage. Consequently, it has not been chosen as a preferred control action.

Higher Reactivity Dolomite

Absorbent material that will absorb SO_2 faster and reach higher utilization can be obtained by four possible methods:

1. Naturally occurring high reactivity dolomite
2. Synthetic manufacturing of high reactivity absorbent
3. Calcination in a CO_2 atmosphere
4. Addition of salts to the absorbent

Higher reactivity absorbent can be used to control sulfur emissions by feeding some of this material into the bed when there is an upward excursion in coal sulfur content.

In many ways this system is similar to the system previously described. Ideally, this system would have a constant dolomite feed regardless of coal sulfur content. Consequently, the Ca/S ratio would decrease as the coal sulfur content increased. Under normal conditions a decrease in retention would result, but by adding absorbent of higher reactivity to the bed the sulfur retention will remain constant. As before, a consequence of this is that the particles within the bed must reach very high utilizations, (90%). Attaining this high utilization has been shown to be possible using the addition of CaCl_2 to dolomite (Shearer, et al, 1979), and has also been shown to be possible by calcination of dolomite in a CO_2 atmosphere (O'Neill et al., 1976). Results of Shearer et al, (1979) also show that the variations in dolomite reactivity could also cover the required range. However, if the steady state design already uses a highly reactive dolomite (like 1337) to obtain a low Ca/S ratio, the reactivity of the feed could only be increased by a small amount, if at all. Consequently, this control action would be ineffective.

As in the previous case, return to steady state would be uncontrollable. Moreover, this system could not take advantage of downward excursions in the coal sulfur content. For these reasons, this system was not pursued further as a preferred control concept.

Adjusting Dolomite Feed Rate

Sulfur retention can be controlled within a small range by adjusting the dolomite feed rate in proportion to changes in the rate of sulfur entering the bed, to maintain a constant nominal Ca/S set point. This system will use a feedforward signal from the PNAA meter to adjust dolomite feed. Long term variations in Ca content of the dolomite or variations in reactivity of the dolomite are accommodated by adjusting the Ca/S set point using a feedback signal of retention. Short-term variations in Ca content or reactivity will be effectively damped by the large mass of the bed. This control system is discussed in more detail in Section 7.5.

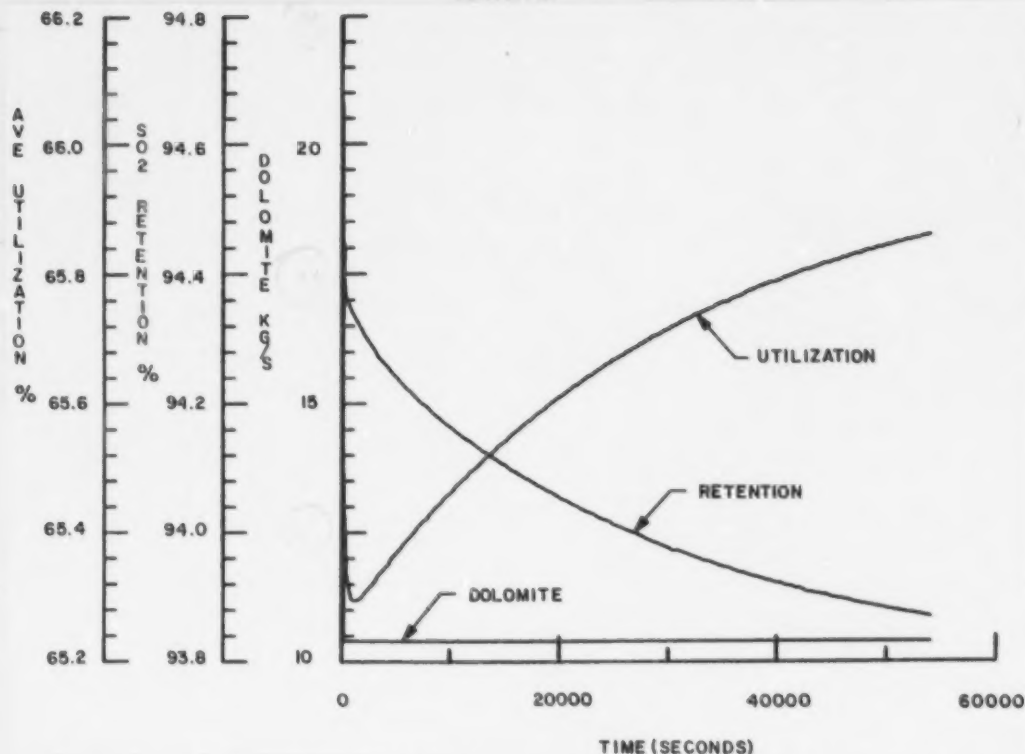


Figure 42. Retention and utilization as a function of time using constant Ca/S ratio control action following a 50% decrease in coal sulfur content (Ca/S = 1.48).

The equipment required to perform this function is normal plant equipment, but must be oversized in order to accommodate excursions in sulfur content. The specific components that will be affected are dolomite feed system, bed particle offtake system and, to a small extent, hot gas clean-up system. Technically this system appears to be viable and simple.

Figure 42 shows the change in retention using this scheme following a step decrease in the amount of sulfur content of the coal. The retention slowly drops, but only by a few tenths of a percent. To understand why this system works so well, the processes that occur following the step change will be reviewed here in detail.

The expression for retention, r , is

$$r = \frac{R_1 - R_0}{R_1} * 100$$

where R_0 is the rate of sulfur leaving the bed and R_1 is the rate of sulfur entering the bed. The expression for sulfur leaving the bed is Equation 3.6. This expression, when combined with expressions 3.7 and 3.8, is proportional to the sulfur entering the bed. In addition, the expression is a function of the bed reaction rate constant, k_1 and the parameter that determines the shape of the sulfur generation function, a .

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Immediately following a step change in the sulfur content of the coal, both R_1 and R_0 are increased by the same proportion. Consequently, the ratio r does not change. The value of r will change when the reaction rate constant k_1 changes or "a" changes. The value of k_1 will change only when there is a shift in the population distribution. This population distribution was shown in Section 5 to have little effect on retention as long as the Ca/S ratio was held constant. The reason for this is that the major source and sink terms in the population distribution equations are increased and decreased proportionately.

The value of R_0 and r will also change when "a" changes. The change in "a" represents a change in the sulfur generation function. From the parametric study of the sulfur generation function in Section 5, it was shown that large changes of the sulfur generation function do not significantly affect the retention except at very high levels of retention. However, it is unlikely that the sulfur generation function will change enough to significantly affect the values of R_0 and r .

An added advantage of this system is the ability of the system to account for variations in the reactivity of dolomite particles. This is done by adjusting the ratio of dolomite feed to sulfur feed in response to long-term trends in retention changes.

The only foreseeable potential technical disadvantage to this control system is that the amount of elutriated fines may increase as the dolomite feed is increased. If one assumes that generation of dolomite fines is proportional to dolomite feed rate, and that the rate of attrition at steady state is similar to the rate found by the NCB in their Leatherhead facility using 1337 dolomite (Roberts et al, 1977), half of the elutriated material will be fly ash. Consequently, the particulate loading of the hot gas will increase by 1% for every 2% increase in dolomite flow. Using the maximum sulfur excursion this would cause a 23% increase in the rate of elutriation for a short period of time. For reasonable average excursions, the elutriation rate would change by about $\pm 10\%$. These increases are well within the observed natural variations in elutriation rates.

The above estimate of elutriation rate also represents a maximum excursion because the rate of generation of dolomite fines is not proportional to dolomite feed. Experiments at Exxon and NCB/CURL indicate that attrition occurs in two stages: initial attrition occurs due to gas release during calcination, while subsequent attrition occurs over a longer period due to abrasive wear of the moving particles. The relative contribution of these two mechanisms is uncertain and varies considerably from one dolomite to another. In addition, the rate of abrasive wear depends on the average utilization because the sulfated stone is harder. As shown in Table 6, the bed utilization distribution remains essentially constant for a given Ca/S ratio. Hence, the rate of abrasive wear is unlikely to be affected by the constant Ca/S control scheme, and only the initial attrition rate will respond to changes in the dolomite feed rate.

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Blending

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This control system operates by substituting low sulfur fuel for part of the coal when there is upward excursion in the coal sulfur content. The substitution is done in order to maintain a constant kg of sulfur per unit of chemical energy input to the fluidized bed. The dolomite flow rate would remain constant under normal operating conditions. Several low sulfur fuels can be considered for this system: natural gas, residual oil, SRC #1, coal-derived liquids (CDL), and low sulfur coal. The additional equipment required for this system depends on the low sulfur fuel to be used. Separate storage and feed systems will be required. Separate sulfur monitoring devices will be required if the sulfur content of the low sulfur fuel would vary significantly. This could be a problem with low sulfur solid fuel.

Technically, this system is feasible. A version of this system is in use by utilities. To comply to the 30-day average, utilities have burned an alternate low sulfur fuel for a few days. However, this system has not been used on a real time blending basis.

If this system is operated on a real time blending basis, there are a few potential technical problems to be considered. For instance, if two fuels are blended, each having different heating values and different sulfur content, the control system must maintain both a constant flow rate of sulfur into the bed as well as the required rate of chemical energy addition. Maintaining this balance is complicated if the heating value of the fuels vary as well as their sulfur content. For example, if the heating value of coal decreased by 10% while the sulfur content remained constant, the mass flow rate of coal into the bed and also the flow rate of sulfur into the bed would increase by 10% to maintain the same plant output. This increase of sulfur flow into the bed would decrease the Ca/S ratio by 10% and bed retention would go down. This problem could be eliminated if both heating value and sulfur content were simultaneously monitored and blending were done to maintain both constant. This is a particular problem if low sulfur coal is used.

A simple solution to this problem exists when the low sulfur fuel has little or no sulfur. Under this condition, the coal feed rate would be adjusted to maintain a constant rate of sulfur addition to the bed. The maximum coal flow rate would be limited by this constant sulfur feed rate. If additional fuel were required, the sulfur free fuel would be added. In any case, this control action alone could not take advantage of downward excursions in the sulfur content of coal.

Some of the low sulfur fuels will have additional problems. Because oil, CDL and gas are fluids, they would require a separate feed system. If oil or CDL is used, care must be taken in the design of this feed system to prevent high temperatures which could cause cracking and coking. This could cause blocking of the feed system. If SRC #1 is used, high temperatures in the feed system should also be avoided because of its low fusion point (457K, 300°F). Above this temperature solid SRC #1 becomes a high viscosity fluid which would cause plugging of the feed system. Blending with low sulfur coal has an additional problem. Its sulfur content varies over a wide range, which would make achieving a constant sulfur input rate difficult.

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Although there are potential technical problems with this control action, none is insurmountable.

No Control Scenario

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In the economic analysis, the technically preferred control concepts are compared with a system that has no control. In order for the no control system to meet sulfur emission standards, the dolomite feed rate must be set at some level above the minimum Ca/S ratio required to maintain the desired percentage retention required. This practice provides a margin so that the integrated retention within the bed complies with emission limits. The margin is required primarily because upward excursions in the coal sulfur content affect the integrated retention more severely than downward excursions. For example, an upward excursion in sulfur content by 50% would decrease the Ca/S ratio from about 1.5 to 0.75. If the excursion remained for several hours, the sulfur retention of the bed could decrease by about 30% (from 90% to 60%). The reverse change in the coal sulfur content would increase retention by only 8% (from 90% to 98%).

For the average retention to comply with standards, a margin is required. The amount of margin required is difficult to define. The minimum required margin will be a function of the magnitude and frequency of sulfur excursions because of the nonlinear response of the bed.

The designer of this system would like to use as small a margin as is necessary, because margin increases the capital and operating costs of the plant. Additional capacity must be included in the dolomite feed and offtake system. Moreover, additional dolomite will be required per unit output. These additions will cause an increase in the cost of electricity and solids disposal problems.

In the following economic analysis, the increase in the cost of electricity as a function of margin will be compared to the increase in the cost of electricity due to installation and operation of constant retention control systems.

7.4 ECONOMIC ANALYSIS

The two technically feasible control systems, constant Ca/S ratio and fuel blending, will be compared to increases in margin. The constant Ca/S ratio system maintains the dolomite feed to the bed in proportion to sulfur input to the bed. Ideally this system will run at the optimum Ca/S ratio and no extra dolomite will be required. However, the dolomite feed system must be sized to accommodate the maximum expected upward excursion in coal sulfur content. The increase in the cost of electricity (COE) for this system has been determined as a function of the maximum expected upward excursion.

The increase in COE for the coal blending scheme is due primarily to increases in the average fuel charge in addition to a small cost for fuel handling equipment. The amount of low sulfur fuel to be added depends on the sulfur content of the low sulfur fuel, the magnitude of the upward excursion and the duration of the excursion. Low sulfur fuel must be added in the correct

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proportion to maintain a constant rate of sulfur input per unit of fuel energy added. Note that this increase in COE is due primarily to increases in the operating costs, whereas the increase in the previous case was primarily a capital cost.

Costing Assumptions

The assumptions used in the economic analysis are listed in Table 11.

TABLE 11. ECONOMIC ASSUMPTIONS USED IN THE COST ANALYSIS*

Plant Life	30 years
Fixed Charge Rate	18%
Capacity Factor	0.80
Escalation Rate	6.5%
Interest Rate	10%
Discrete Levelization Factor	1.88
Coal Consumption	257.7 tons/hr
Coal Heating Value (HHV)	10788 Btu/lb
Coal Cost	0.84 \$/MMBtu
Dolomite Consumption	86.7 tons/hr
Dolomite Cost (1978)**	15 \$/ton
Net Plant Efficiency	0.407
Net Plant Output	663 MWe
Six PNAA Meters (O&M)	1.92×10^6 \$ (60×10^3 \$/yr)
Two PNAA Meters (O&M)	0.64×10^6 \$ (30×10^3 \$/yr)
SRC I Cost	3.10 \$/MMBtu
SRC I Sulfur Content	0.5%
SRC I Heating Value HHV	16000 Btu/lb
No. 2 Oil Cost	3.10 \$/MMBtu
No. 2 Oil Sulfur Content	0.22%
No. 2 Oil Heating Value	19280 Btu/lb
Natural Gas Cost	2.40 \$/MMBtu
Natural Gas Sulfur Content	0%

* All costs in this table are mid-1978 costs.

** Disposal costs not included.

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Equipment Costs

Each of the control systems requires changes in the base case power plant design. The equipment affected by the inclusion of the constant Ca/S ratio control system is the prepared dolomite conveyor, feeders, storage bins, petroc carb system, spent solids valves and surge vessels. The control scheme employing blending will also require changes to the base line design. Additional storage and handling equipment will be required for SRC #1 blending. Blending with No. 2 fuel oil will require increasing the storage and burner capacity of the bed warmup system. Blending with natural gas will require the addition of a gas main and additional in-bed burners.

Changes in the total capital cost for various contingencies in the control schemes can be seen by comparing the costs listed in Table 12.

TABLE 12. INCREMENTAL PLANT INSTALLED COST (\$/kW 1984)

Combination	Constant Ca/S	SRC Coal Blending	Fuel Oil Blending	Natural Gas Blending
A, D, F	21.91	8.23	9.20	8.35
B, D, F	15.10	8.01	8.69	8.10
C, D, F	11.01	7.81	8.21	7.85
A, E, F	16.92	3.24	4.21	3.36
B, E, F	11.11	3.02	3.70	3.10
C, E, F	6.02	2.82	3.22	2.87
A, D, G	23.70	8.56	9.34	8.35
B, D, G	16.12	8.10	8.73	8.10
C, D, G	11.34	7.86	8.26	7.86

Baseline (no control, no margin)

919. \$/kW (1984)

- A - Excursion in coal sulfur content to 5.85%.
- B - Excursion in coal sulfur content to 4.85%.
- C - Excursion in coal sulfur content to 4.29%.
- D - Six nuclear sulfur meters.
- E - Two nuclear sulfur meters.
- F - Four-hour excursion duration.
- G - Five-hour excursion duration.

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Economic Evaluation of the Constant Ca/S Ratio System

Changes in the levelized COE above the baseline system as a function of margin in the dolomite feed and feed system are shown in Figure 43. Curve A represents the additional cost incurred from increased equipment capacity and dolomite costs when margin is added to the base line system. Disposal costs are not included in this economic analysis. If they were, Curve A would have a greater slope. Curve B represents the increase in cost incurred when incorporating the constant Ca/S ratio control system into the base line design. For this curve margin indicates the overcapacity included in the dolomite feed and offtake system (no extra dolomite is required). The amount of overcapacity represents the maximum upward excursion in coal sulfur content which could be handled by this system.

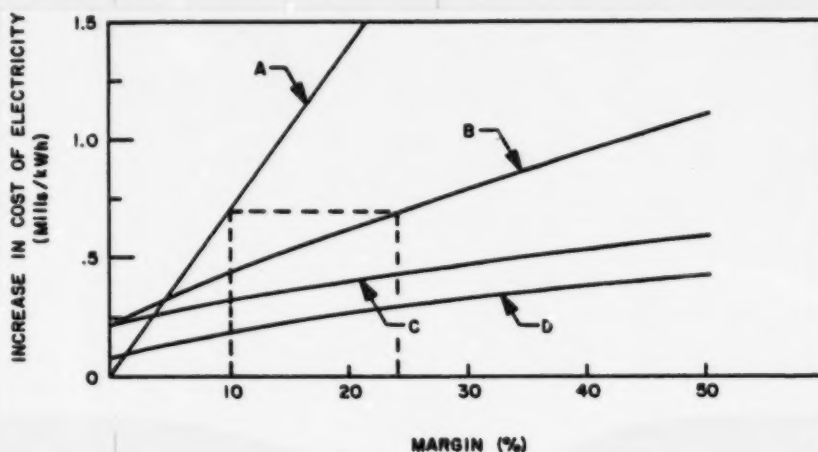


Figure 43. Increase in levelized cost of electricity as a function of margin (A) the additional cost above base line design for added margin in dolomite feed system and dolomite feed (B) cost of constant Ca/S ratio control system as a function margin in dolomite feed system, duration of excursion 19.2 hr (continuous), (C) cost of constant Ca/S ratio control system as a function of margin in dolomite feed system duration of excursion 4 hr, (D) same as C, but uses only two nuclear sulfur meters instead of six.

Comparison of Curve A and B shows the economic advantage or disadvantage of the control system. For example, if running the plant continuously at 10% dolomite feed margin (dashed line on Figure) were required to meet emission standards, a control system incorporating a 24% overcapacity in the dolomite feed system would be competitive. Overcapacity of 24% implies that this control system could maintain retention within a small tolerance for sulfur excursion increases of 24% or smaller.

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If it is assumed that the maximum duration of the maximum excursion is limited to four hours instead of a full day, the constant Ca/S system becomes more economically attractive. The results for this system are shown by Curve C. If two PNAA meters are adequate instead of the six incorporated in the previous cases, and the four hour limit is assumed, the constant Ca/S system is more economically attractive. The results for these assumptions are shown by Curve D.

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The overall economic competitiveness of this system depends on the margin adequate for the no control system. Because of the non linear response of the bed this margin depends on parameters which are not well characterized such as the frequency and magnitude of sulfur variations. It appears that the constant Ca/S ratio control system is competitive with maintaining reasonable dolomite feed margins of 5 to 10 percent. Its competitive standing would improve if dolomite disposal costs were included in this comparison.

Economic Evaluation of the Fuel Blending System

The economic comparison of the fuel blending system to maintaining a constant margin is shown in Figure 44. The cost of this system is not a strong function of the maximum sulfur excursion or its duration. However, it is a strong function of the size and duration of the average sulfur excursion. These two quantities determine the amount of additional low sulfur fuel that will be required.

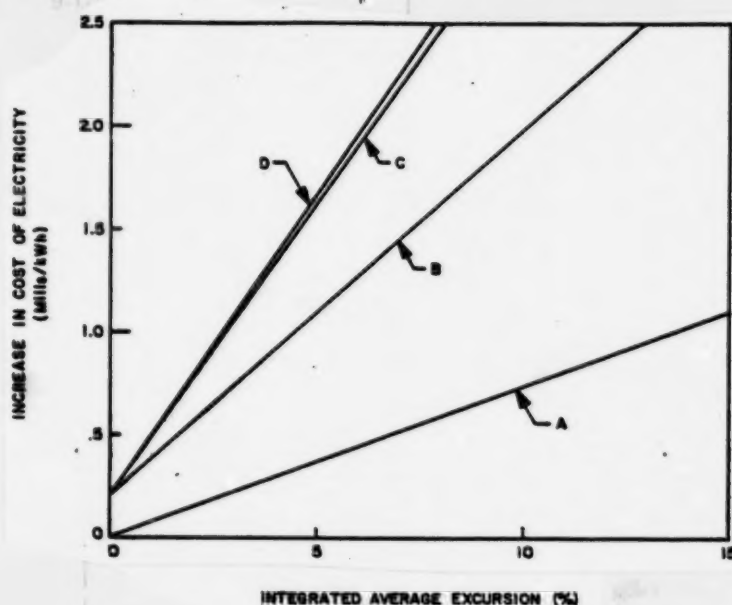


Figure 44. Increase in levelized cost of electricity as a function of the average deviation for (A) increasing dolomite feed margin by the amount equal to the integrated average excursion (B) using natural gas blending (C) using No. 2 oil blending (D) using SRC blending (B, C, D uses six nuclear sulfur meters).

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The abscissa on Figure 44 represents the average upward sulfur excursion. Curve A shows the added cost of increasing the margin of the base line design by an amount equal to the average excursion (this curve is identical to Curve A on the previous figure). Curves B, C, and D show the increase in cost using the fuel blending control system for natural gas, No. 2 oil, and SRC #1 respectively. Curve B, C, and D would shift downward by approximately 0.15 mils if two PNAA meters were used instead of six.

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Economically, fuel blending systems do not appear attractive, mainly because of the high cost of fuel relative to the cost of additional dolomite.

Changes in Control Level

The previous economic analysis has been based on a nominal 90% sulfur retention. If this level is decreased, incremental cost associated with fuel blending will remain the same because the amount of fuel to be added would remain the same and the number of PNAA meters would also remain the same.

If the sulfur retention level were decreased, the cost of the no control option would decrease roughly in proportion to the decrease in the steady state dolomite requirement, i.e., if the steady state dolomite requirement decreased by 10% the incremental cost would also decrease about 10%. The constant Ca/S ratio control system incremental cost would also decrease if the sulfur retention level were decreased. However, the portion of the cost associated with the PNAA meters would not decrease. This cost is represented by the ordinate intercept of Curve B, C and D of Figure 43. The incremental cost above this intercept value due to increases in margin would decrease roughly in proportion to the decrease in the steady state dolomite requirement.

In any event, the relative placement of the control options will not change. Consequently, the conclusions of the economic analysis will remain the same.

7.5 PREFERRED CONTROL SYSTEM

As a result of the previous economic and technical comparison, the preferred control concept is the constant Ca/S ratio concept. Electronically implementing this control system into the plant will require a few logic control elements to manipulate sensor signals and adjust the dolomite flow rate. A simple flow diagram for signal manipulator is shown in Figure 45. The basic control takes the sulfur flow rate signal from the PNAA, sends it through a delay and multiplies it by a factor K' to obtain the desired dolomite flow rate control signal. The delay is to account for delays in the feeding system between the point of sulfur content measurement and the point of injection into the bed. The value of the factor K' is a function of the level of retention required.

To accommodate long-term variations in dolomite Ca content or in dolomite reactivity, a feedback loop using measured retention is incorporated into the control system. This loop adjusts the Ca/S ratio set point on a long-term basis so that the desired retention is maintained. The control system, Figure 45, incorporates a logic block (LB1) that calculates the retention of the bed from the measurements of the sulfur input and output. The difference between the calculated retention and the set point retention is used by a logic block (LB2)

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to determine the desired value of K' . The lag is placed between the summing junction and LB2 is so that the value of K' is changed only in response to definite trends, not noise. Another lag may be required in the dolomite flow rate control line in order to limit the rate of response of the dolomite feed system.

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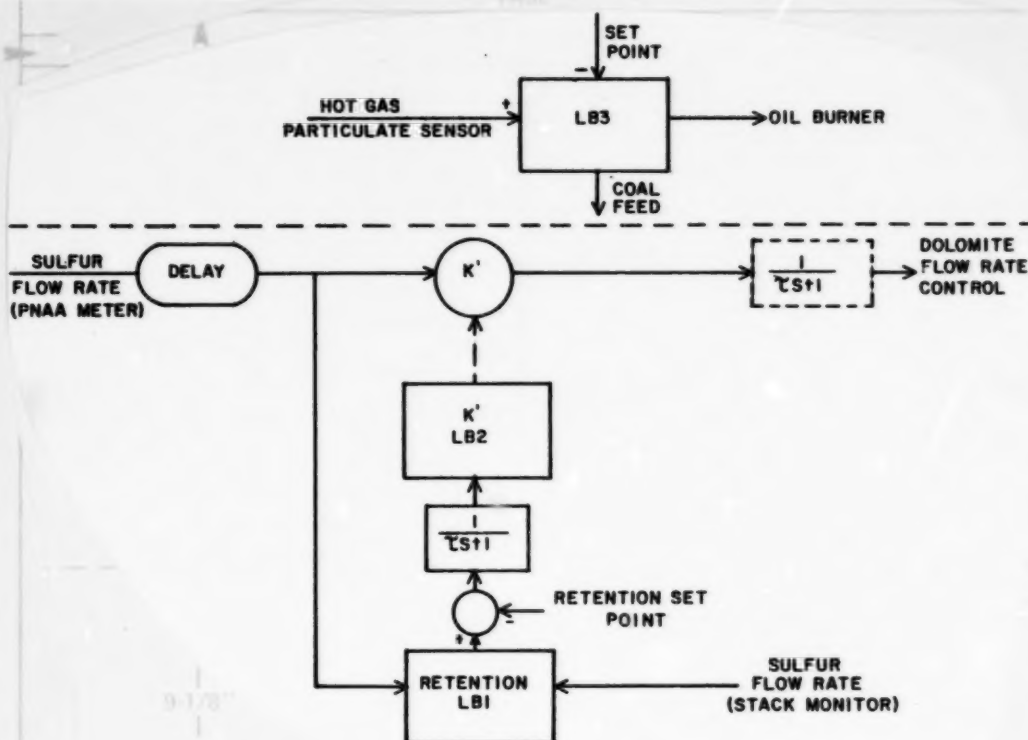


Figure 45. Block diagram of preferred retention control system.

If the dolomite feed rate increases, the bed offtake must also increase. The normal method of scheduling offtake in response to changes in bed pressure drop will be adequate for the sulfur control system.

The model was exercised using this control system (without the retention feedback loop) included in the overall plant control system. The results are shown in Figures 46 through 50. These figures show various important parameters as a function of time following a ramp decrease and increase in the load demand signal for the power plant. The ramp rate for both cases was 5% per minute, which is a typical ramp rate for load maneuvering on a utility system.

The important point to note on these figures is that sulfur retention is controlled to within 1 1/2%. This is due primarily to changes in the bed temperature and its effect on the absorption rate constant. The change of 1 1/2% in retention is acceptable. If the retention feedback loop had been incorporated into the system, the variation of retention would be smaller and the system would return to the original retention set point.

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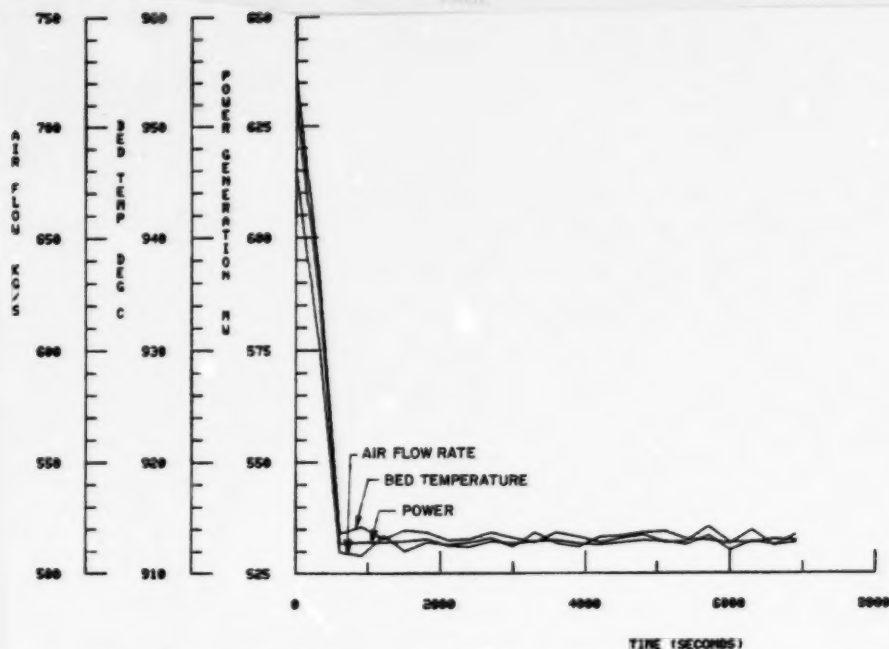


Figure 46. Bed temperature, air flow rate, and power output during a ramp decrease in load demand.

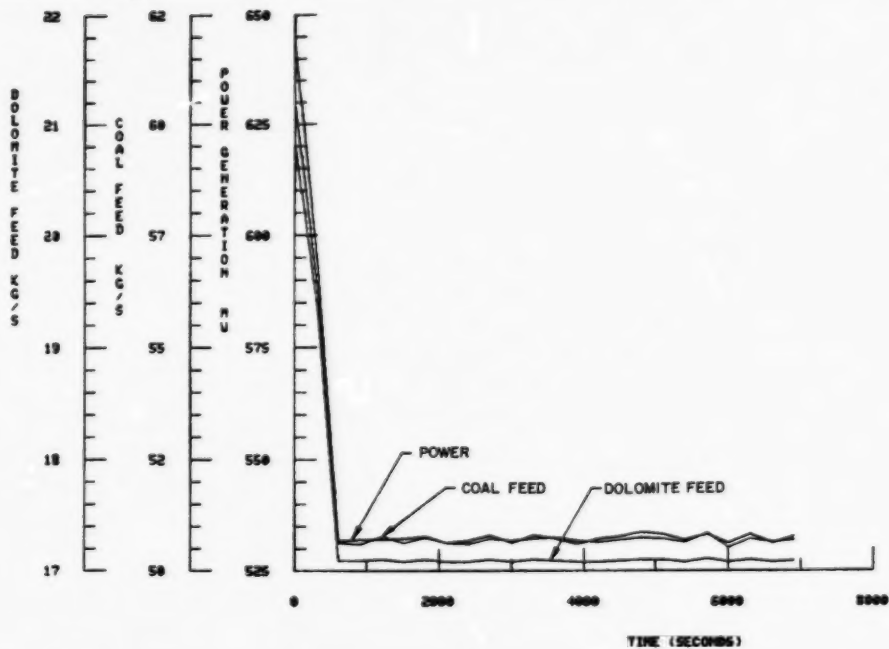


Figure 47. Coal feed, dolomite feed and power output during a ramp decrease in load demand

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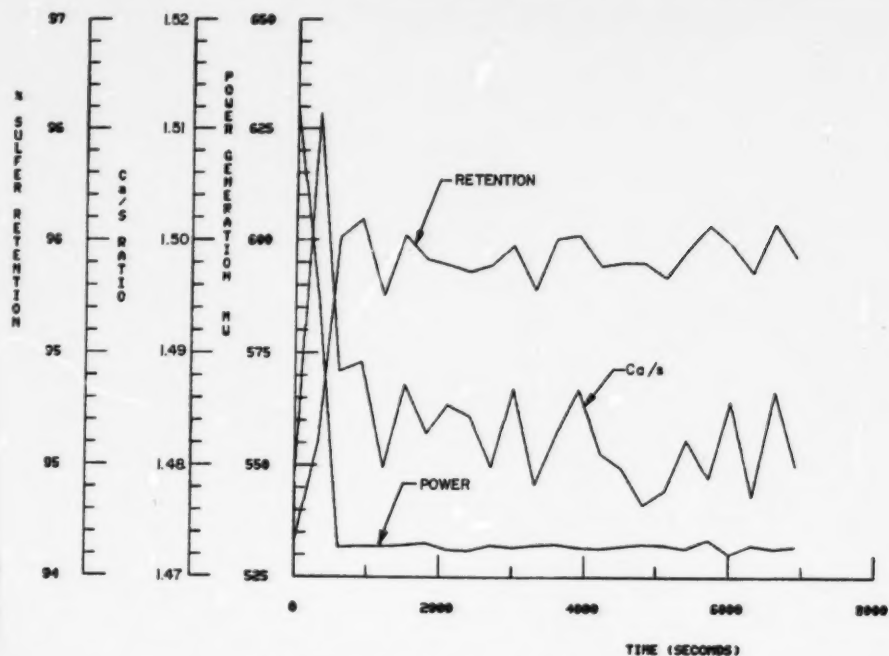


Figure 48. Sulfur retention, Ca/S ratio, and power output following a ramp decrease in load demand.

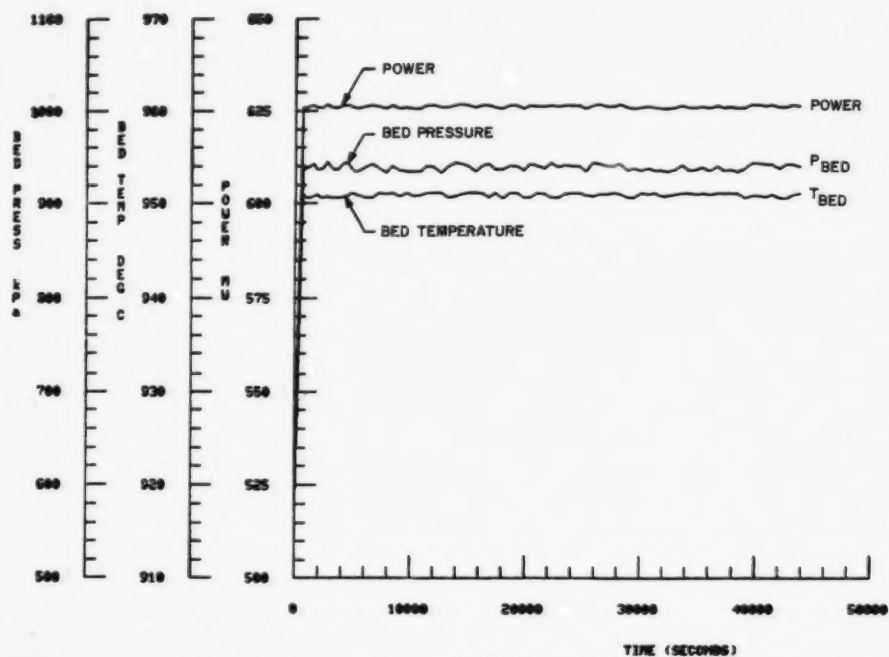


Figure 49. Bed temperature and bed pressure during and following a ramp increase in load demand.

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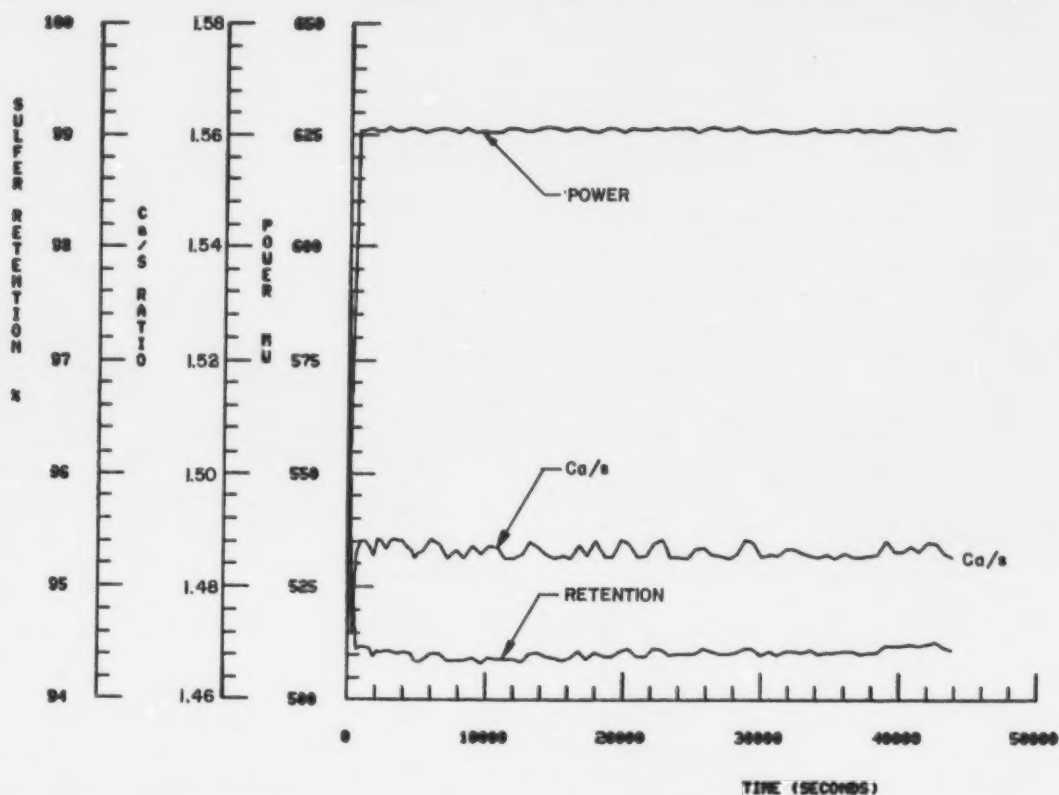


Figure 50. Retention and Ca/S ratio during and following a ramp increase in load demand.

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SECTION 8

EXTENSION OF CONTROL SYSTEMS TO AFB POWER PLANTS

8.1 GENERAL DESCRIPTION

In this section designs of AFB and PFB power plants are contrasted, followed by consideration of the methods of controlling sulfur capture for application with current designs of AFB plants. Finally, methods of control of sulfur capture are reviewed for advanced AFB designs that incorporate fines recycle.

AFB and PFB power plants differ in many ways. Table 13 shows the difference between typical values of key parameters for AFB and PFB plants. AFB plants have lower heat release rates in the bed, lower heat transfer coefficients and lower maximum temperatures. All of these facts inherently imply that the AFB boiler will be much larger per unit of output than a PFB boiler. Consequently, the bed inventory in an AFB is much larger than that of a PFB. This implies longer response times. Because the bed height is lower and velocity higher, the gas residence time in the bed is much shorter.

TABLE 13. COMPARISON OF KEY PARAMETERS OF TYPICAL
AFB AND PFB POWER PLANTS

	AFB	PFB
Heat Release Rate $\text{W/m}^3\text{K}$ (Btu/hr $\text{ft}^3\text{°F}$)	1.1×10^6 (2×10^5)	1.9×10^6 (3.3×10^5)
Heat Transfer Coef. $\text{W/m}^2\text{K}$ (Btu/hr $\text{ft}^2\text{°F}$)	70. (40)	88. (50)
Maximum Temperature K(°F)	1150 (1550)	1245 (1750)
Gas Velocity m/s (ft/s)	2.4 (8)	1.4 (4.5)
Ca/S	3.0 - 5.0	1.5
Bed Height m (ft)	1.22 (4)	2.7 (9)

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Plant load is controlled in different manner than PFB plants. In a PFB plant the bed temperature is allowed to drop in addition to changing the coal and air flow rates to the bed. Steam tubes in the bed may or may not be uncovered during load changes. An AFB plant controls load by changing the coal and air feed rates to the bed. The effect of this is to lower bed height and uncover steam tubes which decrease the amount of steam produced.

AFB plants may have another basic difference. Some designs incorporate a carbon burn-up cell (CBC) into the plant. The purpose of this bed is to burn the residual carbon in the bed offtake stream and the elutriated carbon material caught by the primary gas clean-up device.

8.2 DETAILED DESCRIPTION OF AFB DESIGNS

In a new power plant concept like those incorporating an AFB, there is a large amount of diversity in early designs. Figure 51 shows general outlines of designs developed by three of the major boiler manufacturers (Curtis et al., 1974). The Combustion Engineering design assumed a grassroots facility. The Babcock & Wilcox and the Foster Wheeler concepts were designed for expansion facilities. All three plants were designed for approximately 600 MWe output. Placement of the beds are considerably different for all three concepts.

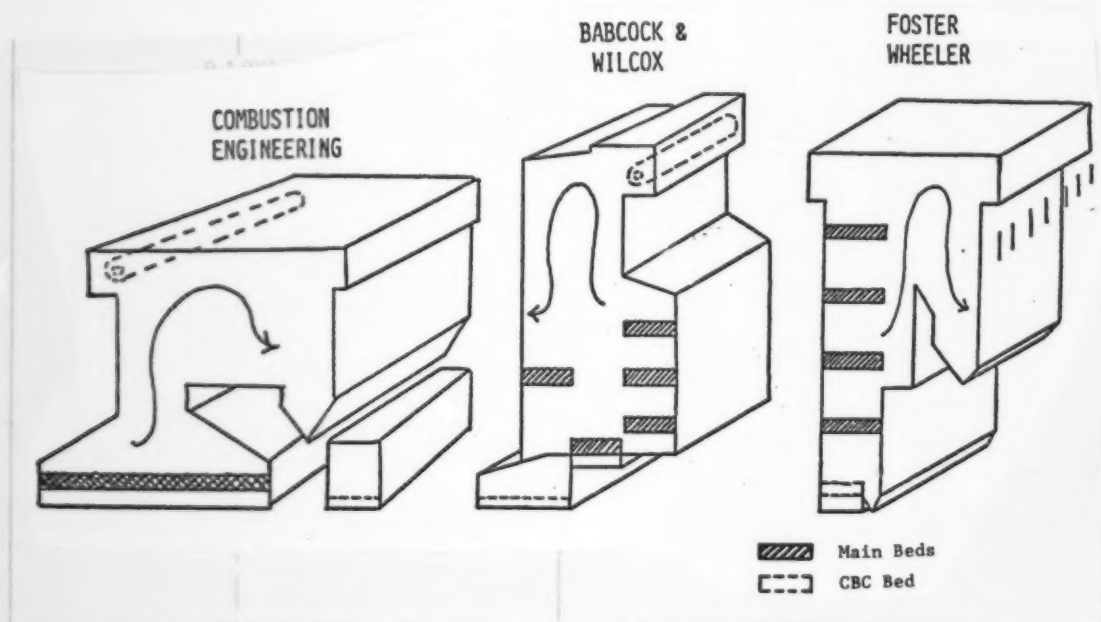


Figure 51. Steam generator design configurations (Curtis et al., 1979).

Of particular interest is the design of the bed. Figures 52 to 54 show detailed sketches of the bed design. Both the B&W and the Combustion Engineering design feed the coal and limestone into the bottom of the bed, while the Foster Wheeler design feeds the coal and limestone by using spreaders on top

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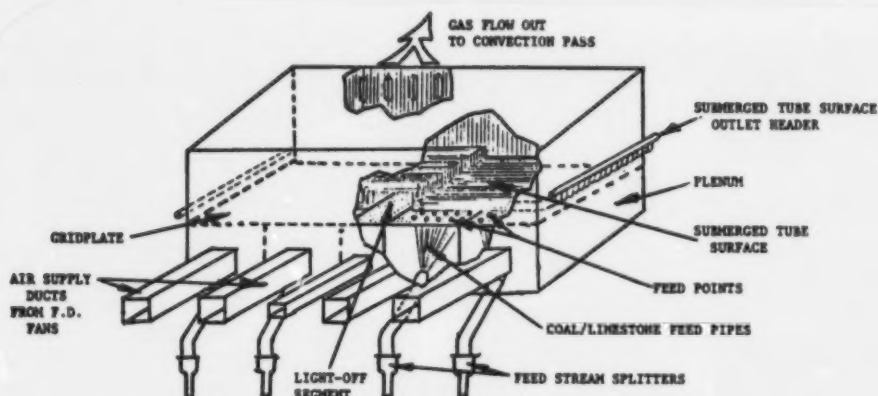
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of the bed. Another major difference among the designs is how the hot gases exit the bed. The Foster Wheeler and the B&W design allow the exhaust gas to pass out of the side of the bed whereas in the Combustion Engineering design the gases pass out of the top of the bed.

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Number of Main Beds	Five
Bed Area (each bed)	1704 ft ² (24'x71')
Segments/Bed	four plus one small (24'x7') light-off segment
Method of Feed	pneumatic, underbed, coal/limestone mixed
Feedpoints/Bed Area	1 per 9 ft ² bed area
Gridplate Type	perforated stainless steel plate

Figure 52. Main bed design - Babcock & Wilcox
(Curtis et al., 1979)

The Ca/S ratio required to obtain 85% sulfur retention in an AFB is anywhere from 3 to 5 for high sulfur coal. This is approximately double the Ca/S ratio expected to be required by the PFB for 90% sulfur removal. Although the Ca/S ratio is much lower for the PFB, the PFB uses dolomite, which is approximately half $MgCO_3$, whereas the AFB uses limestone, which is primarily all $CaCO_3$. For this reason the percentage of the heat release required for calcination is approximately the same, and the amount of solid waste is comparable.

8.3 CANDIDATE CONTROL SCHEMES

Both control systems that were found technically viable for a PFB plant were considered for use with an AFB plant. These schemes are the constant Ca/S ratio control scheme and the low sulfur fuel blending scheme. There is no technical reason why either of these control schemes could not be used in an AFB plant.

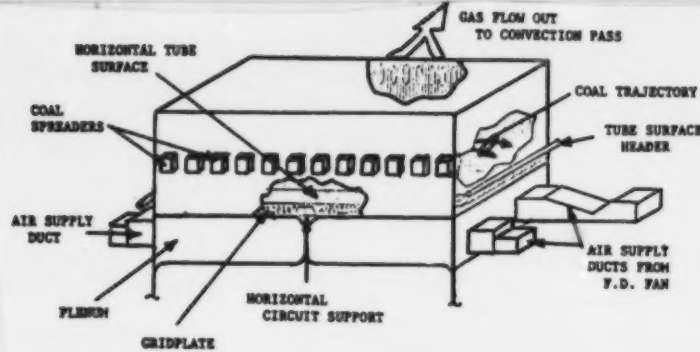
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Number of Main Beds	Four
Bed Area (each bed)	1920 ft ² (30'x64')
Segments/Bed	four
Method of Feed	coal: overbed coal spreader limestone: overbed gravity drop
Feedpoints/Bed Area	coal: 1 spreader per 160 ft ² of bed area limestone: 1 per 1920 ft ² of bed area
Gridplate Type	water filled tubes with nozzle "TEES" through tube membranes

Figure 53. Main bed design - Foster Wheeler Energy Corp.
(Curtis et al., 1979)

The same basic equations should apply equally well to both AFB and PFB combustors. Consequently, the conclusions that were found for PFB combustor population distributions should apply equally well for AFB combustors. Rates of attrition, elutriation and sulfation should be comparable for both beds. For this reason constant Ca/S ratio control should be theoretically viable.

There are only a few design (and economic) problems to be overcome by each system. The primary problem is that a large bed area is required. The cross-sectional area is about three times larger in an AFB plant. Consequently, three times the number of coal and limestone feed points are required. If under bed feed is required, putting overcapacity into this feed system to accommodate constant Ca/S ratio control could be prohibitively expensive. On the other hand, if over bed feed proves to be adequate only a few feed points would be required. Consequently, the cost for overcapacity would be smaller.

Coal blending with low sulfur SRC I could be easily accomplished. However, it is unlikely that the economics are any more attractive than they were

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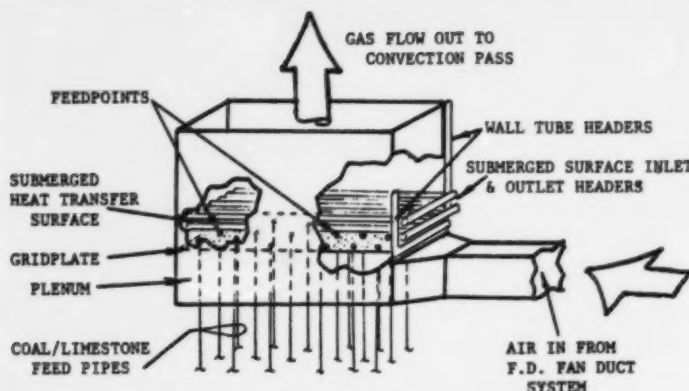


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Number of Main Beds	Twenty-five
Bed Area (each bed)	15 beds with 324 ft ² (9'x36') 10 beds with 153 ft ² (9'x17')
Segments/Bed	one
Method of Feed	pneumatic, underbed, coal/limestone mixed
Feedpoints/Bed Area	1 per 18 ft ² of bed area
Gridplate Type	perforated stainless steel plate

Figure 54. Main bed design - Combustion Engineering
(Curtis et al., 1979)

for PFB plants. Oil and natural gas blending would also be technically viable. Additional fuel feed points would need to be spaced throughout the bed. Again, because of the large required bed area, many would be required.

8.4 ADVANCED AFB CONCEPTS

There has been a recent significant development which raises combustion efficiency several percent while reducing Ca/S ratios to approximately 2.0. This is accomplished by the recycle of fines back to the bed (Lihach, 1979). This concept will not require a carbon burn-up cell, but will require equipment to distribute the fines back into the bed evenly. It is suggested that a significant percentage of sulfur is absorbed on fines above the bed as they are being elutriated. Moreover, a large steady state population of fines will be built up in the bed. The mathematical model developed for this study is inadequate for assessing sulfur capture, or sulfur capture transients for these conditions.

The value of fines recycle is being explored by several investigations. Three companies, B&W, GE, and Lurgi, have all realized the value of small particle recycle and are actively developing workable systems. While all three companies are exploring recycle, their concepts differ significantly in fluidizing velocity, rate of fine recycle, and bed particle size distributions.

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Recycle of fines to the bed will change the transient response because hold-up times in the recycle system could be long. Consequently, changes in the production of fines or the rate of sulfation of fines will not appear in the recycle fines feed to the bed for sometime. The time lag will be determined by the specific design of the plant.

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Extension of this work to recycle systems would be valuable not only to study transients and control, but also to investigate sulfur capture as a function of particle attrition, fines recycle rate and other parameters which are of question in advanced AFB designs.

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SECTION 9

RECOMMENDATIONS

To determine the actual economic attractiveness of the proposed control method the typical time dependent sulfur variations in coal feed must be defined. Specifically, the size of excursion, the duration of excursion, the ramp rate of change or frequency spectrum must be determined. This will aid in determining the margin in dolomite feed rate that is required to control variations in sulfur emissions. More accurate economic trade-offs could then be obtained.

One of the recommended control methods requires the Ca/S ratio to remain constant. This implies that the dolomite feed be increased and decreased in response to changes in coal sulfur content. To reduce this method to practice, experiments should be performed to determine the effect of changing feed rate on attrition and elutriation.

Moreover, the model should be extended to study advanced AFB concepts that rely on the recycle of elutriated fines to the bed to significantly improve sulfur capture. The extension of the model could aid in the evaluation of various effects and options such as attrition rates, recycle rates, cyclone capture efficiency, freeboard height, coal sulfur contents, and load control.

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APPENDIX A

THE PRODUCTION AND ABSORBTIVITY OF FINES

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Attrition and elutriation are closely tied. Practically all of the absorbent elutriated from the bed is very fine material formed during the attrition of particles. This fine material can typically account for 20 to 80% of the solid material leaving the bed. For this reason both attrition and elutriation are major processes and must be accurately included in the bed model.

There are three important points about the attrition and elutriation processes. First, the average utilization of the elutriated fine material does not usually match the average utilization of the bed offtake. This can be explained by noting that fresh sorbent particles which are not highly utilized, wear more readily than particles that have aged in the bed. Second, a large percentage of the calcium fed to the bed is elutriated as very fine material which is a result of attrition of the bed material. Third, fine material of the size that is elutriated typically make up only a very small percentage of the bed population. This can be explained by reasoning that fine material produced by attrition is rapidly elutriated.

The first two of these points are illustrated by the data in Table A.1, which is a summary of some of the test data from the British National Coal Board (Roberts, 1977) and Exxon (Hoke, 1978). The NCB data shows the utilization of the elutriated material is about 15% lower than material taken directly from the bed. However, the opposite trend appears in the Exxon data. This unexpected trend is probably due to the fact that the primary cyclone material was recycled to the bed. Due to the recycle, the fines were able to reach higher utilization before being passed by the primary cyclone.

TABLE A.1. ELUTRIATION DATA FOR EXPERIMENTAL
PFB COMBUSTORS USING 1337 DOLOMITE

	NCB 6/2	NCB 7	Exxon 43.4-43.5
Fluid. Velocity M/S	0.76	2.13-1.98	1.8-1.7
Ca/S Molar	1-1.5	1.1-2.5	0.5-1.25
Util. Elutriated Material %	44-39*	44*	73-78†
Util. of Bed Offtake %	56-71	60-75	53-64
% Ca Feed in Elutriated Material	25*	85*	40†

*Primary Cyclone

†Secondary Cyclone

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The third point is illustrated in Table A.2 which contains the size distribution of the bed material at various times during test NCB-6. Less than 1% of the bed is of a size smaller than 250 μ m. As mentioned earlier, the reason for this small population is the large rate of elutriation of these small particles. Steady state bed populations can be estimated by setting the rate of attrition equal to the rate of elutriation for a small size range. We then have

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$$b_x = \frac{f_x A}{E_x}$$

where b_x is the weight fraction of the bed of size x , A is the total rate of attrition, f_x is the fraction of the total fines produced in size x and E_x is the rate of elutriation. Table A.3 shows typical values for E_x , f_x , and the resulting b_x for a total attrition rate equal to 40% of the feed rate for data corresponding to the PFB being modeled. (Commercial Plant Design Definition, GE Report FE-2357-23, 1979). The weight fraction of the fine material in the bed b_x is very small. For the largest size, the weight fraction is 0.1% of the bed and the weight fractions for smaller sizes are orders of magnitude smaller.

TABLE A.2. SIZE DISTRIBUTIONS OF SAMPLES
OF BED MATERIAL DURING TEST
NCB6 (ROBERTS, 1977)

Size μ	6/1A	6/1B % Larger than Size by Wt.	Post 6/1	6/2A	6/2B
+ 1700	5	8	2.5	5	8.5
+ 850	36.5	42	47.5	28.5	43.5
+ 500	88.5	87	84.5	83.5	85
+ 422	93.5	91	-	89.5	90
+ 250	99	99.5	99.5	99	99
+ 211	99.5	-	-	99.5	99.5
+ 150	100	100	100	-	-
+ 104				100	100

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TABLE A.3. FINES SIZE DISTRIBUTION FRACTION, ELUTRIATION,
AND STEADY STATE WEIGHT FRACTION FOR THE PFB
BEING STUDIED

Size μ	f_x	E_x (kg/s)	b_x
125-63	0.20	3.9 E2	9.2 E-4
63-31	0.20	3.1 E3	1.6 E-4
31-16	0.20	1.6 E4	2.3 E-5
16-8	0.20	5.3 E4	6.8 E-6
8-0	0.20	1.8 E5	2.0 E-6

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An upper limit of the absorption of SO_2 by these small size particles can be estimated assuming that the absorption by these particles is chemical reaction limited. The rate for this chemical reaction can be estimated by using the TGA (Thermogravimetric Analysis) rate data for 74-129 μ m particles at zero utilization. At any time, the ratio between the sulfur absorbed by the fines and the sulfur absorbed by the total bed is given by

$$F = \frac{K_f b_f}{K_1}$$

where K_f is the absorption rate constant for the fines, b_f is the fraction of fines in the bed and K_1 is the bed integrated rate constant. A typical value of this ratio for the system being studied is 0.007. This means that less than 1% of the sulfur captured by the bed is absorbed by the fine particles in the bed.

One conclusion from this is that the sulfur contained by the fine particles captured in the cleanup system is mostly due to the sulfur that they absorbed while they were still attached to large particles. For this reason, sulfur absorption by small particles can be ignored in this model.

Recycle of fines to the bed will considerably alter the above conclusion. Recycle of fines will produce a much larger steady state concentration of fines in the bed. This will cause a larger percentage of the sulfur to be absorbed by the fine particles and consequently increase their utilization.

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APPENDIX B

COMPUTER PROGRAM SIMULATION

The computer model has been structured in a modular format as shown in Figure B.1. Each subroutine simulates a specific process or piece of equipment, so each routine was developed and thoroughly checked before being combined with the rest of the system. The program runs in the batch mode. The mainline accepts control inputs (e.g., title, run duration, and print and plot intervals), initializes the data from a restart file, determines the calculation time, and calls the appropriate subroutines. The output subroutine is called after the calculations at each time step are complete. If required by the user, this subroutine will produce a printed report or file to be used for plotting. As described below, the remainder of the subroutines represent specific portions of the PFB plant.

The overall plant controller subroutine (Figure B.2) ensures that plant output satisfies plant load demand. As the plant operating conditions change during a transient, the controller, through a series of iterative calculations, determines the variations in key plant parameters. These calculations involve determining the required coal feed rate based on relationships involving bed heat generation, bed operating temperature, and bed air flow based on the gas turbine inlet guide vane (IGV) position. From these calculations, the gas and steam turbine output power levels are determined, and the calculations are repeated until the combined output equals the new plant load demand.

The bed inventory routine (Figure B.3) performs a mass balance on the bed material. The bed material is divided into 11 groups according to particle sizes. Each group represents a specific range of particle sizes and the total of 11 sizes account for all the mass of the bed. In addition, the particles of bed material are separated into 10 utilization groups, thus forming a doubly indexed array of 110 groupings. A mass balance is performed on each element in the array accounting for fresh dolomite feed, attrition, elutriation and bed offtake. Changes in overall bed mass and weighted average utilization and size distribution are then determined by summing over the entire array.

The heat balance subroutine (Figure B.4) calculates the products of combustion and the energy released as heat. The heat of reaction is calculated as a summation of these major terms:

- Energy released in the combustion process
- Energy released in SO_2 sorption reaction
- Energy released/absorbed as a result of bed temperature changes
- Energy absorbed in calcination of dolomite feed

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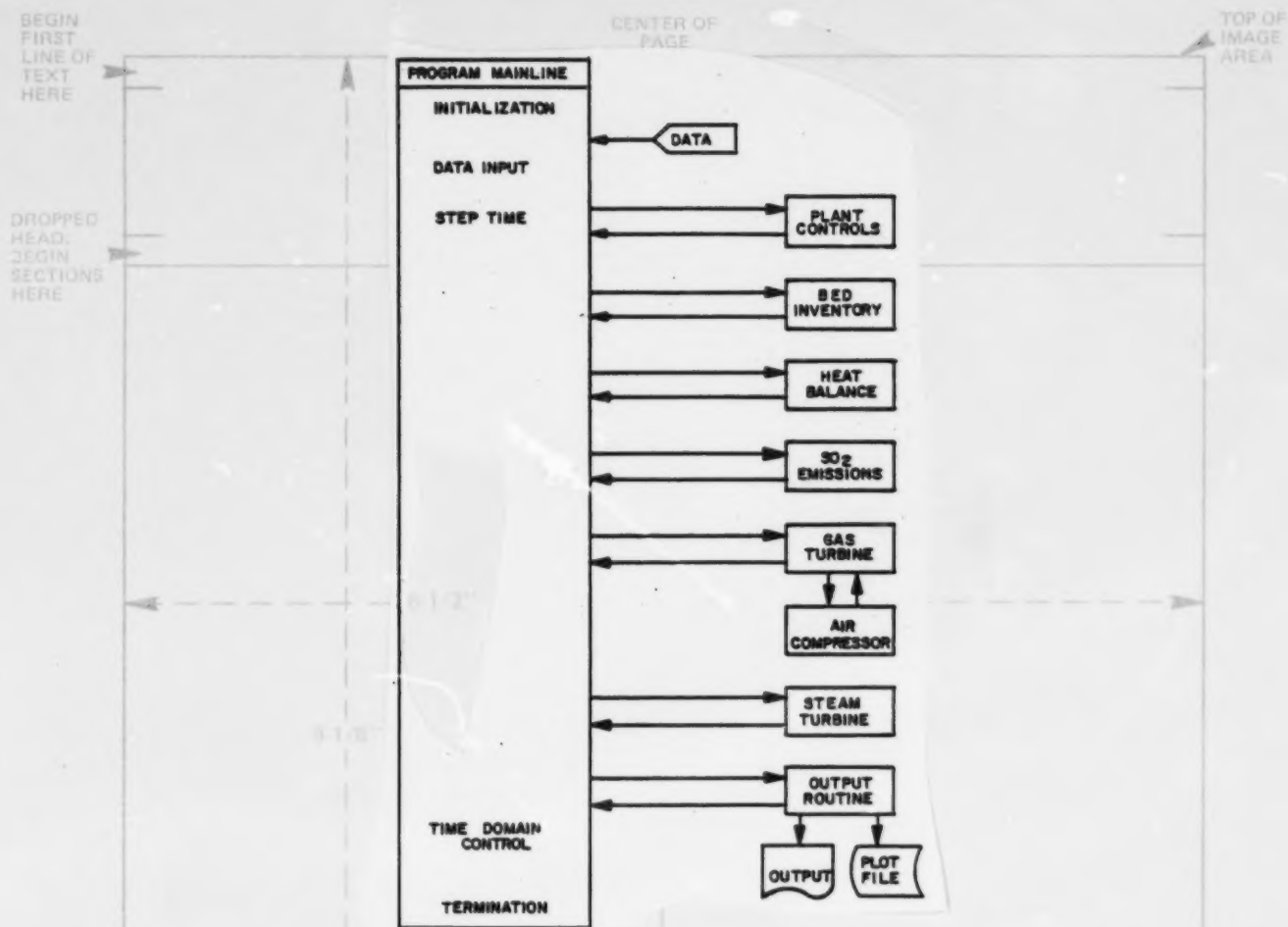


Figure B.1. Structure of the computer simulation.

The temperature of the gas leaving the bed closely equals the bed temperature; therefore, the effluent heat content can be determined using the bed temperature and data from the gas tables. The remainder of the heat of reaction (minus a fixed percent for losses) is assumed to be transferred to the steam. The value of energy in the steam calculated in this manner is compared to the value computed using the log-mean temperature difference between the bed and steam within the internal bed tubes. The two values are compared and the difference is driven to near zero by iterating on bed temperature (and coal feed) to find the required heat transfer rate and thus steam flow.

The SO_2 sorption routine (Figure B.5) calculates the sulfur released during combustion and absorption by the bed, as well as resulting changes in bed utilization. Having calculated the gas composition and bed conditions, it is possible to determine the minimum fluidizing velocity, the superficial and terminal velocities, and the bed height at the minimum fluidizing velocity and actual superficial velocity. The reactivity of the bed is a function of utilization and size distribution. The rate of combustion is dependent on the amount

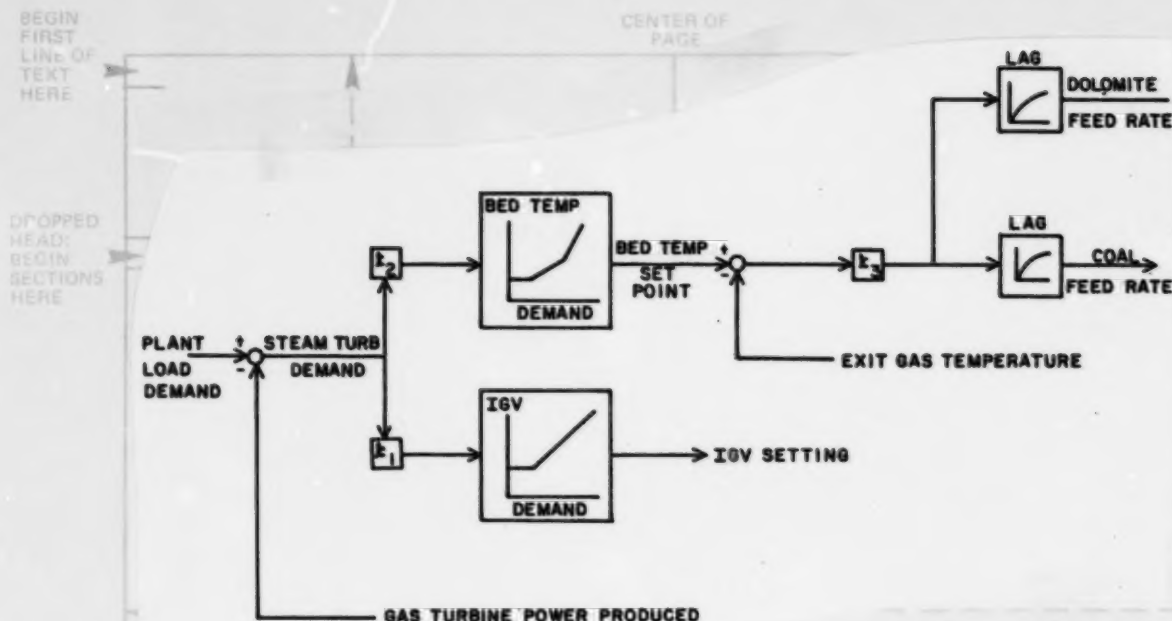


Figure B.2. Power plant controls.

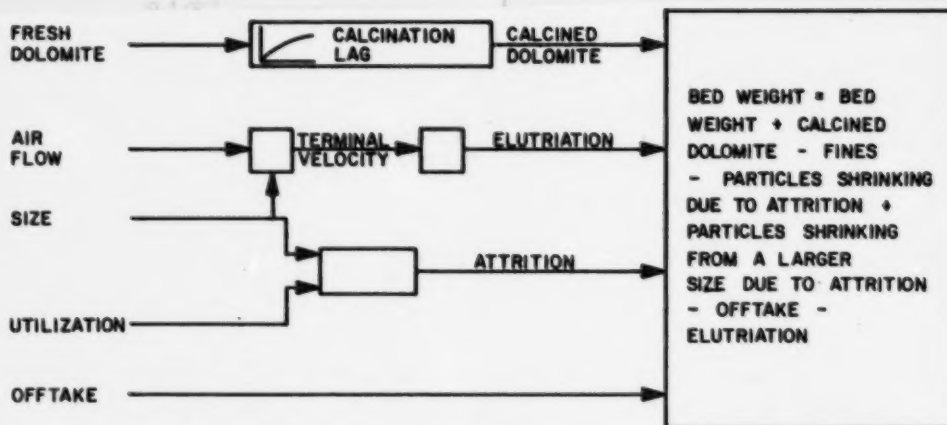


Figure B.3. Bed inventory model.

of oxygen available. Increasing the excess air causes the coal to burn faster and in effect releases the sulfur deeper in the bed nearer the bottom coal feed ports. This effect can be accounted for in the model through the use of a special term, a (see Eq. 3.4), an expression involving the excess combustion air. The time dependent sulfur release is then calculated and used in an expression for the variation in utilization (du/dt) so that the bed utilization can be updated.

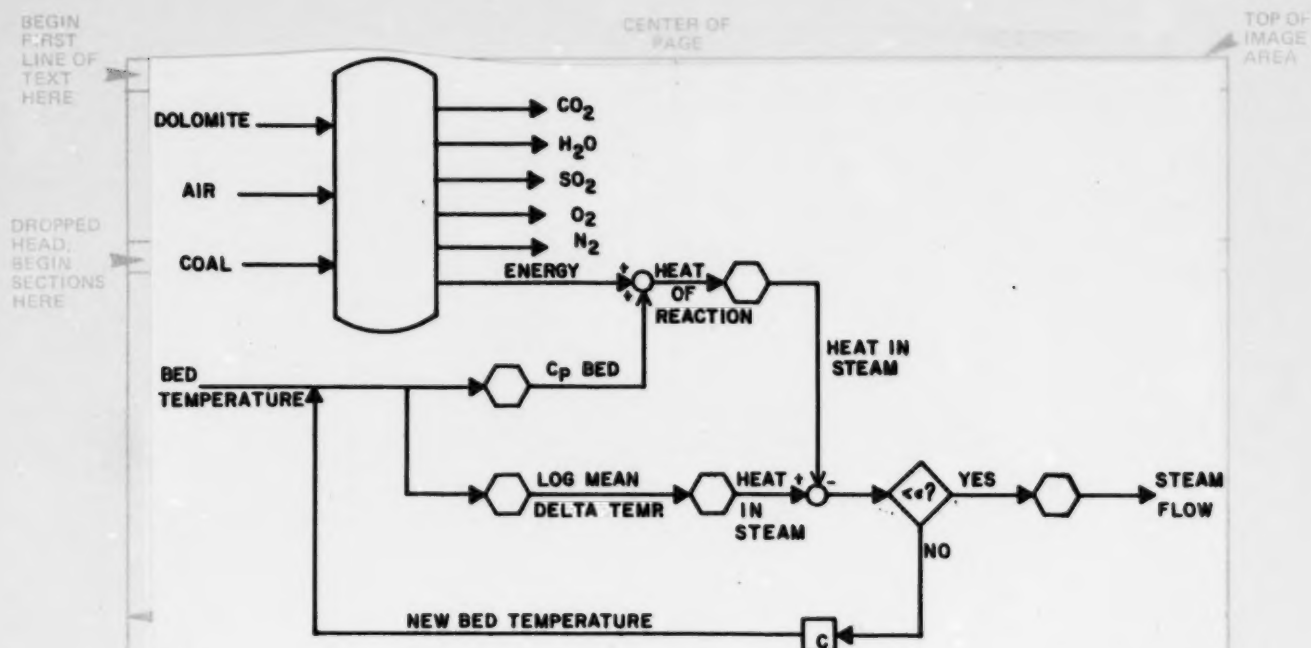


Figure B.4. Energy balance routine.

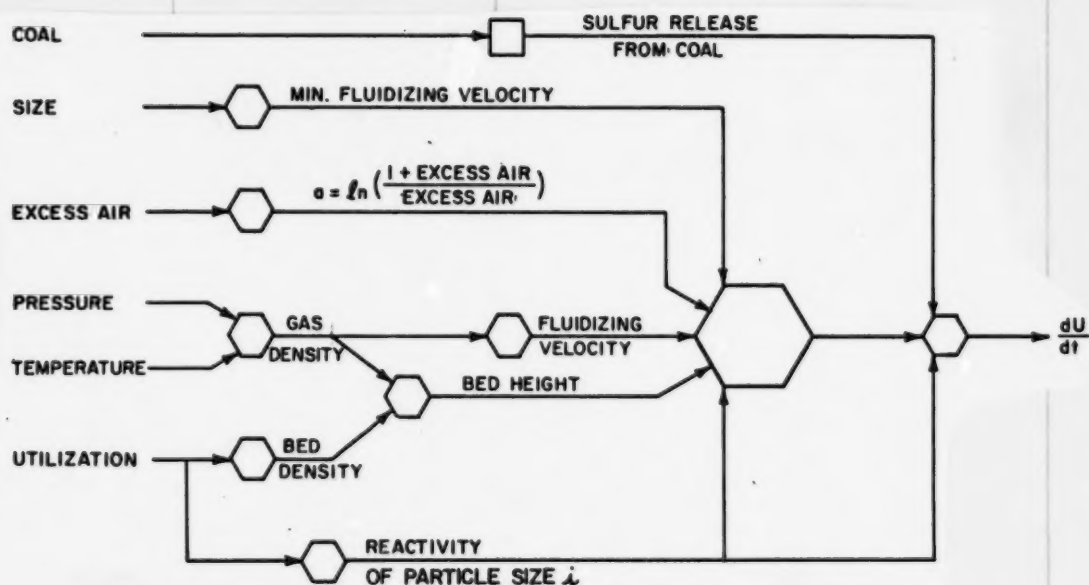


Figure B.5. Sulfur retention model.

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The purpose of the simulation is to evaluate potential SO_2 emission control methods. The primary concern, therefore, is developing a plant model with sufficient accuracy to adequately evaluate the relative performance of various potential SO_2 emission control methods. To meet this objective, the bed model is most important and the steam turbine, gas turbine, and air compressor models (Figure B.6) are less significant. Accordingly, these latter representations have been simplified by assuming constant efficiencies and constant speeds. Further, the time constant for the entire steam turbine is very close to the calculation interval of the program. Therefore, for the purposes of evaluating relative emission control methods, the steam turbine appears to have virtually instantaneous response. Thus it is represented with a steady-state equation following a time lag (numerical integration) representing delays in steam conditions due to the volume of steam within the piping and manifolding. Similarly, Figure B.6 shows the simplified gas turbine and compressor models used. The double iterative loop solves for bed pressure, turbine inlet flow and turbine inlet pressure simultaneously.

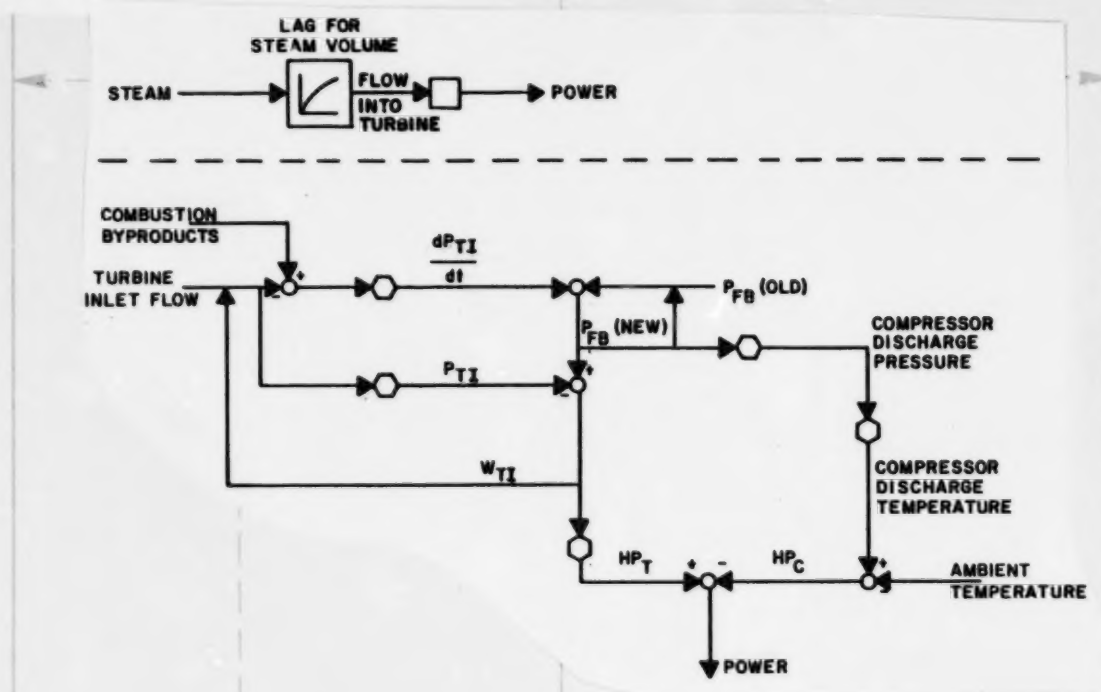


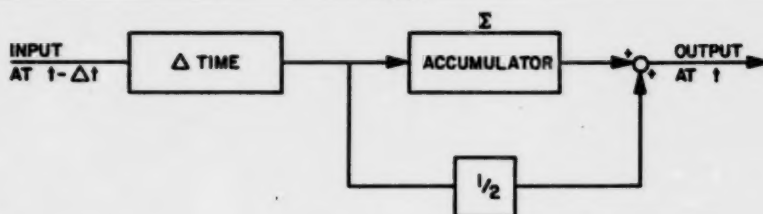
Figure B.6. Combined cycle model.

The integration algorithm used throughout the simulation requires only a single pass, thus isolating the input from the output. The inputs for a given time interval are calculated from the outputs of the previous time interval. The integrator is a modification of a simple accumulator, which compensates for the inherent lag caused by using inputs calculated from output of the previous time interval. Figure B.7a is a block diagram of the integrator and Figure B.7b compares its response to that of an ideal integrator.

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Figure B.7a. Block diagram of integrator algorithm.

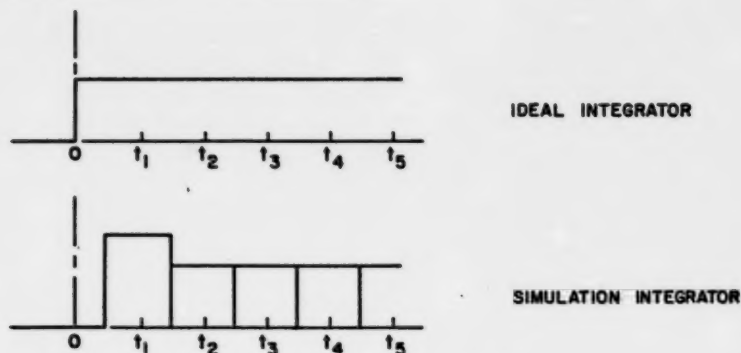


Figure B.7b. Response of the integrator algorithm to a unit pulse at time $t = 0$.

Figure B.8* is a series of flow charts which translates the block diagrams of theory and assumptions into a computer simulation. Listings of the mainline and all the subroutines are in Figure B.9.**

RUNNING THE PROGRAM

In order to run the computer model, the appropriate control cards are needed (see Figure B.10). This deck setup includes data cards which specify the title, duration of run, print and plot intervals, and plot file if needed. When the calculate time is greater than or equal to the stop time, a new stop time is read. If the new stop time is less than the current calculate time, the program halts; otherwise, the computer reads new print and plot intervals and the simulation continues as before. Figure B.11 is a listing of the restart file used to initialize the program (read from file number 15). Every hour the current bed conditions are recorded in file number 14 which may be used to start another simulation in the future. In this way, restart capability is provided. Table B.1 lists typical values for the design point conditions. At the initial time, and at intervals specified by the user, output is printed showing current bed conditions. The first column of results are in SI units and the second in engineering units as shown in Figure B.12. The bed population distribution is also printed in kilogram moles with each set of output.

*Figure B.8 begins on page 125
**Figure B.9 begins on page 136

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 130\$ LIBRARY L1
 140\$ FORTY
 150\$ SELECTA FEP7/S02EMISB
 160\$ SELECTA FEP7/S02PLANT
 170\$ SELECT 088A330F/CFILE
 180\$ EXECUTE
 190\$ PRMFL L1, R, R, 802E/T323/LSTGLIB1
 200\$ PRMFL 14, R/W, S, FEP7/S02RST2
 220\$ LIMITS 65, 45K, -4K, 9K
 230\$ DATA 15
 240\$ SELECTA FEP7/RSCAS1.5
 250\$ DATA 05
 260 EVALUATION OF CFCC DESIGN POINT CASE
 270 STEP CHANGE IN FEED SIZES AT 180 SEC.
 280 CA/S FEED RATIO=1.5
 290 0, 3600.
 300 90, 60
 310 DOLSI2
 320 72000.
 330 360, 120
 400 0
 410\$ ENDJOB

Figure B.10. Sample set of control cards required to make run the model.

TABLE B.1. TYPICAL VALUES FOR DESIGN POINT CONDITIONS

Coal Flow	61.7 kg/s	136.0 lb/sec
Dolomite Flow	20.8 kg/s	45.9 lb/sec
Air Flow	680 kg/s	1498.2 lb/sec
Bed Height	2.8 m	9.0 ft
Superficial Velocity	1.25 m/s	4.0 ft/sec
Bed Temperature	950°C	1745°F
Coal Sulfur	4%	4%
Steam Turbine Power	493 MW	
Gas Turbine Power	360 MW	
Compressor Power	207 MW	
Net Power	153 MW	

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20 0.5960E 02 0.4800E 01 0.1000E 01 0.3900E 01
30 0.1111E 02 0.1000E 02 0.9600E 01
40 0.2100E 04 0.1925E 04 0.1750E 04 0.1575E 04
50 0.1400E 04 0.1225E 04 0.1050E 04 0.8750E 03
60 0.7000E 03 0.5250E 03 0.3500E 03
70 0.1062E 01 0.1014E 01 0.9642E 00 0.9114E 00
80 0.8551E 00 0.7945E 00 0.7285E 00 0.6554E 00
90 0.5722E 00 0.4733E 00 0.3469E 00
100 0.4158E 03 0.3526E 03 0.5992E 03 0.8990E 03
110 0.1115E 04 0.1178E 04 0.1316E 04 0.1432E 04
120 0.1318E 04 0.6837E 03 0.1303E 03
130 0.7932E 03 0.6411E 03 0.1024E 04 0.1448E 04
140 0.1711E 04 0.1741E 04 0.1893E 04 0.2024E 04
150 0.1850E 04 0.9615E 03 0.1863E 03
160 0.2079E 04 0.2285E 04 0.2825E 04 0.2892E 04
170 0.2669E 04 0.2278E 04 0.2188E 04 0.2145E 04
180 0.1850E 04 0.9286E 03 0.1786E 03
190 0.1942E 04 0.1556E 04 0.2328E 04 0.2884E 04
200 0.2976E 04 0.2701E 04 0.2674E 04 0.2648E 04
210 0.2272E 04 0.1117E 04 0.2081E 03
220 0.2555E 04 0.2895E 04 0.4327E 04 0.4886E 04
230 0.4691E 04 0.4046E 04 0.3857E 04 0.3708E 04
240 0.3107E 04 0.1496E 04 0.2752E 03
250 0.1072E 04 0.1088E 04 0.6479E 04 0.7128E 04
260 0.6321E 04 0.5212E 04 0.4835E 04 0.4568E 04
270 0.3791E 04 0.1816E 04 0.3354E 03
280 0.4910E 02 0.4444E 02 0.7925E 02 0.1070E 05
290 0.2450E 05 0.9525E 04 0.6930E 04 0.5977E 04
300 0.4838E 04 0.2356E 04 0.4623E 03
310 0.4406E 02 0.5296E 02 0.1057E 03 0.1780E 03
320 0.2428E 03 0.2631E 05 0.1752E 05 0.1192E 05
330 0.8985E 04 0.4349E 04 0.8984E 03
340 0.2379E 02 0.5338E 02 0.1540E 03 0.3311E 03
350 0.5393E 03 0.7077E 03 0.2590E 05 0.4530E 05
360 0.4513E 05 0.2455E 05 0.5105E 04
370 0.4304E 01 0.1099E 02 0.3405E 02 0.7611E 02
380 0.1266E 03 0.1679E 03 0.2251E 03 0.1082E 04
390 0.8300E 04 0.7263E 04 0.1850E 04
400 0.2507E 08 0.4508E 06 0.9679E-02 0.6655E 01
410 0.4500E-04 0.3049E-02 0.2268E 01 0.6693E 00
420 0.1407E 03 0.4967E 03 0.6177E 03 0.3993E 02
430 0.6170E 02 0.2080E 02 0.1414E 02 0.9994E 00
440 0.1487E 01 0.7520E-01 0.5291E-02 0.9296E 02
450 0.1006E 04 0.9872E 03 0.8914E 03 0.9533E 03
460 0.9055E 03
470 0.4813E 01 0.3386E 00 0.2189E-09 0.8481E 05
480 0.4621E 15
490 0.2268E 01 0.3049E-02 0.2778E 01 0.1850E 01
500 0.1227E 01 0.5054E 03 0.1062E 03 0.2101E 02
510 0.1550E 07 0.7154E 06 0.8348E 06 0.1088E 04
520 0.6715E 03 0.6670E 03 0.6307E 03
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Figure B.11. Listing of restart file.

The final pages of this report are a glossary of the variables used in the simulation. All units are SI, but variables ending with "1" are in engineering units. For example, air flow into the bed is WA (kg/s) and WA1 (lb/sec).

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LISTING OF FEP7/IOUT

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EVALUATION OF CFCC DESIGN POINT CASE
STEP CHANGE IN FEED SIZES AT 180 SEC.
CA/S FEED RATIO=1.5

TIME = 0. SECONDS

COAL COMPOSITION	WEIGHT %	MOLE %
CARBON	59.6	46.6163
HYDROGEN	4.8	45.0520
NITROGEN	1.0	0.6704
SULFUR	3.9	1.1439
OXYGEN	11.1	6.5173
SURFACE WATER	10.0	0.
ASH	9.6	0.

CONTROL SYSTEM	628.18 (MW)	842405.13 (HP)
TOTAL POWER	61.70 (KG/S)	136.02 (LB/SEC)
COAL FLOW	20.80 (KG/S)	46.66 (LB/SEC)
DOLomite	679.59 (KG/S)	1498.23 (LB/SEC)
AIR FLOW	14.14 (KG/S)	31.18 (LB/SEC)
BED OFFTAKE	25070000.0 (J/KG)	10780.10 (BTU/LB)
HIGH HEATING VALUE	1.4870	
CA/S FEED RATIO	1046.0163 (MICRON)	0.041171 (IN)
AVE PARTICLE SIZE	94.6820 (X)	
SULFUR RETENTION	912.58 (KPA)	132.37 (PSI)
BED PRESSURE	40.61 (X)	
PLANT EFFICIENCY	65.49 (X)	
AVERAGE UTILIZATION		

BED INVENTORY	0.025 (KG/S)	0.06 (LB/SEC)
TOTAL FINES PRODUCED	450829.5 (KG)	993698.70 (LB)
BED WEIGHT	6.84 (KG/S)	15.08 (LB/SEC)
ELUTRIATION	20.96 (KG/S)	46.21 (LB/SEC)
FRESH DOLomite FEED		

SO2 RELEASE & CAPTURE	4.813 (KG/S)	10.61 (LB/SEC)
SO2 PRODUCED	0.08 (MOL/S)	
SULFUR ENTERING BED	0.0040 (MOL/S)	
SULFUR LEAVING BED	0.0030496 (G/CC)	0.1904 (LB/'CU FT)
GAS DENSITY	2.2677 (G/CC)	141.575 (LB/'CU FT)
SOLIDS DENSITY	2.778 (M)	9.114 (FT)
BED HEIGHT	1.23 (M/S)	4.03 (FT/SEC)
SUPERFICIAL VELOCITY	1.36 (M/S)	4.46 (FT/SEC)
EFFECTIVE VELOCITY		
SO2 EMISSIONS	0.1655E-09 (KG/J)	0.3847E-06 (LB/BTU)
TOTAL SO2 EMISS	0.1835E-09 (KG/J)	0.4267E-06 (LB/BTU)
MINIMUM BED HEIGHT	1.8497 (M)	6.07 (FT)
MIN FLUIDIZING VELOCITY	0.6693 (M/S)	2.1958 (FT/SEC)

Figure B.12. Sample output of the simulation.

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HEAT BALANCE
STOICHIOMETRIC AIR FLOW 1114.30 (LB/SEC)
EXCESS AIR 234.10 (LB/SEC)
HEAT OF REACTION 2078457. (HP)
EXCESS AIR FLOW 319.39 (LB/SEC)
CO2 RELEASED 1037.61 (LB/SEC)
N2 RELEASED 54.19 (LB/SEC)
H2O RELEASED 58.76 (LB/SEC)
SO2 RELEASED 0.56 (LB/SEC)
BED OUTLET GAS FLOW 1470.70 (LB/SEC)
BED TEMPERATURE 1747.73 (DEG F)

GAS TURBINE & AIR COMPRESSOR
TURBINE INLET FLOW 1392.048 (LB/SEC)
PFB EXHAUST HEAT 959346. (HP)
TURBINE INLET PRESSURE 118.452 (PSI)
TURBINE INLET TEMPERATURE 1661.687 (DEG F)
TURBINE EXIT TEMPERATURE 979.437 (DEG F)
PRESSURE DROP FROM BED 13.905 (PSI)
TURBINE POWER (GROSS) 485462.30 (HP)
TURBINE POWER (NET) 207817.11 (HP)
IGV SETTING (1 OPEN)
AMBIENT TEMPERATURE 59.00 (DEG F)
COMPRESS DISCHARGE TEMP 549.91 (DEG F)
COMPRESS DISCHARGE PRESS 135.07 (PSI)
COMPRESS POWER 276840.58 (HP)

STEAM TURBINE
INLET FLOW 1042.98 (LB/SEC)
INLET HEAT 1119197. (HP)
INLET PRESSURE 3500.00 (PSI)
OUTLET POWER 1458738.80 (HP)
681536.04 (HP)

SIZE, MOLES OF CALCIUM

2100.00	1925.00	1750.00	1575.00	1400.00	1225.00	1050.00	875.00	700.00	525.00	350.00
2.9	2.0	3.3	5.0	6.2	6.5	7.3	8.0	7.3	3.8	0.7
4.4	3.6	5.7	8.1	9.5	9.7	10.5	11.3	10.3	5.3	1.0
11.6	12.7	15.7	16.1	14.6	12.7	12.2	11.9	10.3	5.2	1.0
10.6	8.7	12.9	16.0	16.5	15.0	14.9	14.7	12.6	6.2	1.2
14.2	16.1	24.1	27.2	25.1	22.5	21.4	20.6	17.3	8.3	1.5
6.0	6.0	36.0	39.6	35.1	29.0	26.9	25.4	21.1	10.1	1.9
0.3	0.2	0.4	59.5	136.2	53.0	38.5	33.2	26.9	13.1	2.6
0.2	0.3	0.6	1.0	1.3	146.3	97.4	66.3	50.0	24.2	5.0
0.1	0.3	0.9	1.8	3.0	3.9	144.0	251.9	250.9	136.5	28.4
0.0	0.1	0.2	0.4	0.7	0.9	1.3	6.0	46.1	40.4	10.3

Figure B.12. (Continued)

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Figure B.12. (Continued)

BOTTOM OF IMAGE AREA, OUTSIDE DIMENSION FOR TABLES AND ILLUSTRATIONS

COAL COMPOSITION	WEIGHT %	MOLE %
CARBON	59.6	46.8163
HYDROGEN	4.8	45.0520
NITROGEN	1.0	0.8704
SULFUR	3.9	1.1439
OXYGEN	11.1	6.6173
SURFACE WATER	10.0	0.
ASH	9.6	0.
CONTROL SYSTEM		
TOTAL POWER	625.89 (MW)	839332.27 (HP)
COAL FLOW	61.70 (KG/S)	136.02 (LB/SEC)
DOLomite	20.80 (KG/S)	45.86 (LB/SEC)
AIR FLOW	679.59 (KG/S)	1498.23 (LB/SEC)
BED OFFTAKE	19.88 (KG/S)	43.83 (LB/SEC)
HIGH HEATING VALUE	25070000.0 (J/KG)	10780.10 (BTU/LB)
CA/S FEED RATIO	1.4870	
AVE PARTICLE SIZE	1046.0166 (MICRON)	0.041171 (IN)
SULFUR RETENTION	94.2337 (%)	
BED PRESSURE	912.18 (KPA)	132.31 (PSI)
PLANT EFFICIENCY	40.46 (%)	
AVERAGE UTILIZATION	65.49 (%)	
BED INVENTORY		
TOTAL FINES PRODUCED	0.026 (KG/S)	0.06 (LB/SEC)
BED WEIGHT	450829.9 (KG)	993899.62 (LB)
ELUTRIATION	6.84 (KG/S)	15.09 (LB/SEC)
FRESH DOLomite FEED	20.88 (KG/S)	46.04 (LB/SEC)
SO2 RELEASE & CAPTURE		
SO2 PRODUCED	4.813 (KG/S)	10.61 (LB/SEC)
SULFUR ENTERING BED	0.08 (MOL/S)	
SULFUR LEAVING BED	0.0043 (MOL/S)	
GAS DENSITY	0.0028176 (G/CC)	0.1759 (LB/'CU FT)
SOLIDS DENSITY	2.2677 (G/CC)	141.575 (LB/'CU FT)
BED HEIGHT	2.813 (M)	9.228 (FT)
SUPERFICIAL VELOCITY	1.33 (M/S)	4.36 (FT/SEC)
EFFECTIVE VELOCITY	1.44 (M/S)	4.73 (FT/SEC)
SO2 EMISSIONS	0.1794E-08 (KG/J)	0.4171E-06 (LB/BTU)
TOTAL SO2 EMISS	0.1835E-09 (KG/J)	0.4267E-06 (LB/BTU)
MINIMUM BED HEIGHT	1.8497 (M)	6.07 (FT)
MIN FLUIDIZING VELOCITY	0.6949 (M/S)	2.2799 (FT/SEC)
HEAT BALANCE		
STOICHIOMETRIC AIR FLOW	505.46 (KG/S)	1114.33 (LB/SEC)
EXCESS AIR	106.18 (KG/S)	234.08 (LB/SEC)
HEAT OF REACTION	1550686. (KW)	2079470. (HP)
EXCESS AIR FLOW	21.006 (%)	
CO2 RELEASED	144.836 (KG/S)	319.31 (LB/SEC)

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N2 RELEASED 470.657 (KG/S) 1037.61 (LB/SEC)
O2 RELEASED 24.580 (KG/S) 54.19 (LB/SEC)
H2O RELEASED 26.654 (KG/S) 58.78 (LB/SEC)
SO2 RELEASED 0.278 (KG/S) 0.61 (LB/SEC)
BED OUTLET GAS FLOW 666.98 (KG/S) 1470.43 (LB/SEC)
BED TEMPERATURE 953.48 (DEG C) 1748.26 (DEG F)

GAS TURBINE & AIR COMPRESSOR

TURBINE INLET FLOW 631.155 (KG/S) 1391.444 (LB/SEC)
PTB EXHAUST HEAT 715544. (KW) 959544. (HP)
TURBINE INLET PRESSURE 816.348 (KPA) 118.397 (PSI)
TURBINE INLET TEMPERATURE 905.492 (DEG C) 1661.886 (DEG F)
PRESSURE DROP FROM BED 526.598 (DEG C) 979.877 (DEG F)
TURBINE POWER (GROSS) 95.830 (KPA) 13.900 (PSI)
TURBINE POWER (NET) 361.79 (MW) 485168.58 (HP)
IGV SETTING (% OPEN) 152.43 (MW) 204405.00 (HP)
0.3994
AMBIENT TEMPERATURE 15.00 (DEG C) 59.00 (DEG F)
COMPRESS DISCHARGE TEMP 290.64 (DEG C) 555.15 (DEG F)
COMPRESS DISCHARGE PRESS 930.87 (KPA) 135.01 (PSI)
COMPRESS POWER 208.77 (MW) 279858.97 (HP)

STEAM TURBINE

INLET FLOW 473.44 (KG/S) 1043.74 (LB/SEC)
INLET HEAT 835202. (KW) 1120006. (HP)
INLET PRESSURE 24129.00 (KPA) 3500.00 (PSI)
INLET POWER 1088.18 (MW) 1459270.08 (HP)
OUTLET POWER 493.49 (MW) 661778.98 (HP)

SIZE, MOLES OF CALCIUM

2100.00	1925.00	1750.00	1575.00	1400.00	1225.00	1050.00	875.00	700.00	525.00	350.00
2.3	2.0	3.3	5.0	6.2	6.5	7.3	8.0	7.3	3.8	0.7
4.4	3.6	5.7	8.1	9.6	9.7	10.5	11.3	10.3	5.3	1.0
11.6	12.7	16.7	16.1	14.8	12.7	12.2	11.9	10.3	5.2	1.0
10.8	8.7	12.9	16.0	16.5	15.0	14.9	14.7	12.6	6.2	1.2
14.2	16.1	24.1	27.2	26.1	22.5	21.4	20.6	17.3	8.3	1.6
6.0	6.0	36.0	39.6	35.1	29.0	26.9	25.4	21.1	10.1	1.9
0.3	0.2	0.4	59.5	136.2	53.0	38.5	33.2	26.9	19.1	2.6
0.2	0.3	0.6	1.0	1.3	146.3	97.4	66.3	50.0	24.2	5.0
0.1	0.3	0.9	1.8	3.0	3.9	144.0	251.9	250.9	136.5	24.4
0.0	0.1	0.2	0.4	0.7	0.9	1.3	6.0	46.1	40.4	12.3

TIME = 10.0 SECONDS

COAL COMPOSITION	WEIGHT %	MOLE %
CARBON	59.6	46.6183
HYDROGEN	4.8	48.0520
NITROGEN	1.0	0.6704
SULFUR	3.9	1.1439
OXYGEN	11.1	6.5173
SURFACE WATER	10.0	0.
ASH	9.6	0.

Figure B.12. (Continued)

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CONTROL SYSTEM		
TOTAL POWER	626.04 (MW)	839526.90 (HP)
COAL FLOW	61.70 (KG/S)	136.02 (LB/SEC)
DOLomite	20.80 (KG/S)	45.86 (LB/SEC)
AIR FLOW	679.59 (KG/S)	1498.23 (LB/SEC)
BED OFFTAKE	19.88 (KG/S)	43.63 (LB/SEC)
HIGH HEATING VALUE	25070000.0 (J/KG)	10760.10 (BTU/LB)
CA/S FEED RATIO	1.4870	
Ave PARTICLE SIZE	1046.0169 (MICRON)	0.041171 (IN)
SULFUR RETENTION	94.2338 (%)	
BED PRESSURE	912.04 (KPA)	132.29 (PSI)
PLANT EFFICIENCY	40.47 (%)	
AVERAGE UTILIZATION	65.49 (%)	
BED INVENTORY		
TOTAL FINES PRODUCED	0.026 (KG/S)	0.06 (LB/SEC)
BED HEIGHT	450930.3 (KG)	993900.43 (LB)
ELUTRIATION	6.85 (KG/S)	15.10 (LB/SEC)
FRESH DOLomite FEED	20.88 (KG/S)	46.04 (LB/SEC)
SO2 RELEASE & CAPTURE		
SO2 PRODUCED	4.813 (KG/S)	10.61 (LB/SEC)
SULFUR ENTERING BED	0.06 (MOL/S)	
SULFUR LEAVING BED	0.0043 (MOL/S)	
GAS DENSITY	0.0028167 (G/CC)	0.1758 (LB/'CU FT)
SOLIDS DENSITY	2.2677 (G/CC)	141.575 (LB/'CU FT)
BED HEIGHT	2.613 (M)	8.229 (FT)
SUPERFICIAL VELOCITY	1.33 (M/S)	4.36 (FT/SEC)
EFFECTIVE VELOCITY	1.44 (M/S)	4.73 (FT/SEC)
SO2 EMISSIONS	0.1794E-08 (KG/J)	0.4171E-06 (LB/BTU)
TOTAL SO2 EMISS	0.1839E-09 (KG/J)	0.4257E-06 (LB/BTU)
MINIMUM BED HEIGHT	1.8497 (M)	6.07 (FT)
MIN FLUIDIZING VELOCITY	0.6950 (M/S)	2.2803 (FT/SEC)
HEAT BALANCE		
STOICHIOMETRIC AIR FLOW	505.45 (KG/S)	1114.32 (LB/SEC)
EXCESS AIR	106.16 (KG/S)	234.09 (LB/SEC)
HEAT OF REACTION	1550831. (KW)	2079262. (HP)
EXCESS AIR FLOW	21.007 (S)	
CO2 RELEASED	144.636 (KG/S)	319.30 (LB/SEC)
H2 RELEASED	470.657 (KG/S)	1037.61 (LB/SEC)
O2 RELEASED	24.581 (KG/S)	54.19 (LB/SEC)
H2O RELEASED	26.654 (KG/S)	58.78 (LB/SEC)
SO2 RELEASED	0.278 (KG/S)	0.61 (LB/SEC)
BED OUTLET GAS FLOW	667.00 (KG/S)	1470.48 (LB/SEC)
BED TEMPERATURE	953.42 (DEG C)	1746.15 (DEG F)
GAS TURBINE & AIR COMPRESSOR		
TURBINE INLET FLOW	631.062 (KG/S)	1391.240 (LB/SEC)
PFB EXHAUST HEAT	715510. (KW)	969486. (HP)
TURBINE INLET PRESSURE	816.238 (KPA)	118.381 (PSI)
TURBINE INLET TEMPERATURE	905.503 (DEG C)	1661.905 (DEG F)
TURBINE EXIT TEMPERATURE	526.606 (DEG C)	979.891 (DEG F)
PRESSURE DROP FROM BED	95.600 (KPA)	13.886 (PSI)

Figure B.12. (Continued)

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TURBINE POWER (GROSS) 361.73 (MW) 465087.01 (HP)
TURBINE POWER (NET) 152.56 (MW) 204613.45 (HP)
IGV SETTING (% OPEN) 0.9994
AMBIENT TEMPERATURE 15.00 (DEG C) 59.00 (DEG F)
COMPRESS DISCHARGE TEMP 290.37 (DEG C) 554.66 (DEG F)
COMPRESS DISCHARGE PRESS 930.73 (KPA) 134.99 (PSI)
COMPRESS POWER 208.55 (MW) 279668.95 (HP)

STEAM TURBINE 473.37 (KG/S) 1043.56 (LB/SEC)
INLET FLOW 635082. (KW) 1119845. (HP)
INLET HEAT 24129.00 (KPA) 3500.00 (PSI)
INLET PRESSURE 1088.17 (MW) 1459253.34 (HP)
INLET POWER 493.46 (MW) 661771.38 (HP)
OUTLET POWER

SIZE, HOLES OF CALCULUM

2100.00	1925.00	1750.00	1575.00	1400.00	1225.00	1050.00	875.00	700.00	525.00	350.00
2.3	2.0	3.3	5.0	6.2	6.5	7.3	8.0	7.3	3.6	0.7
4.4	3.6	5.7	6.1	9.5	9.7	10.5	11.3	10.3	5.3	1.0
11.6	12.7	15.7	16.1	14.8	12.7	12.2	11.9	10.3	5.2	1.0
10.6	8.7	12.9	16.0	16.6	15.0	14.9	14.7	12.6	6.2	1.2
14.2	16.1	24.1	27.2	26.1	22.5	21.4	20.6	17.3	8.3	1.5
6.0	6.0	36.0	39.5	35.1	29.0	26.9	25.4	21.1	10.1	1.9
0.3	0.2	0.4	59.5	136.2	53.0	36.5	33.2	26.9	13.1	2.6
0.2	0.3	0.6	1.0	1.3	146.3	97.4	66.3	50.0	24.2	5.0
0.1	0.3	0.9	1.6	3.0	3.9	144.0	251.9	250.9	136.5	28.4
0.0	0.1	0.2	0.4	0.7	0.9	1.3	6.0	46.1	40.4	10.3

Figure B.12. (Continued)

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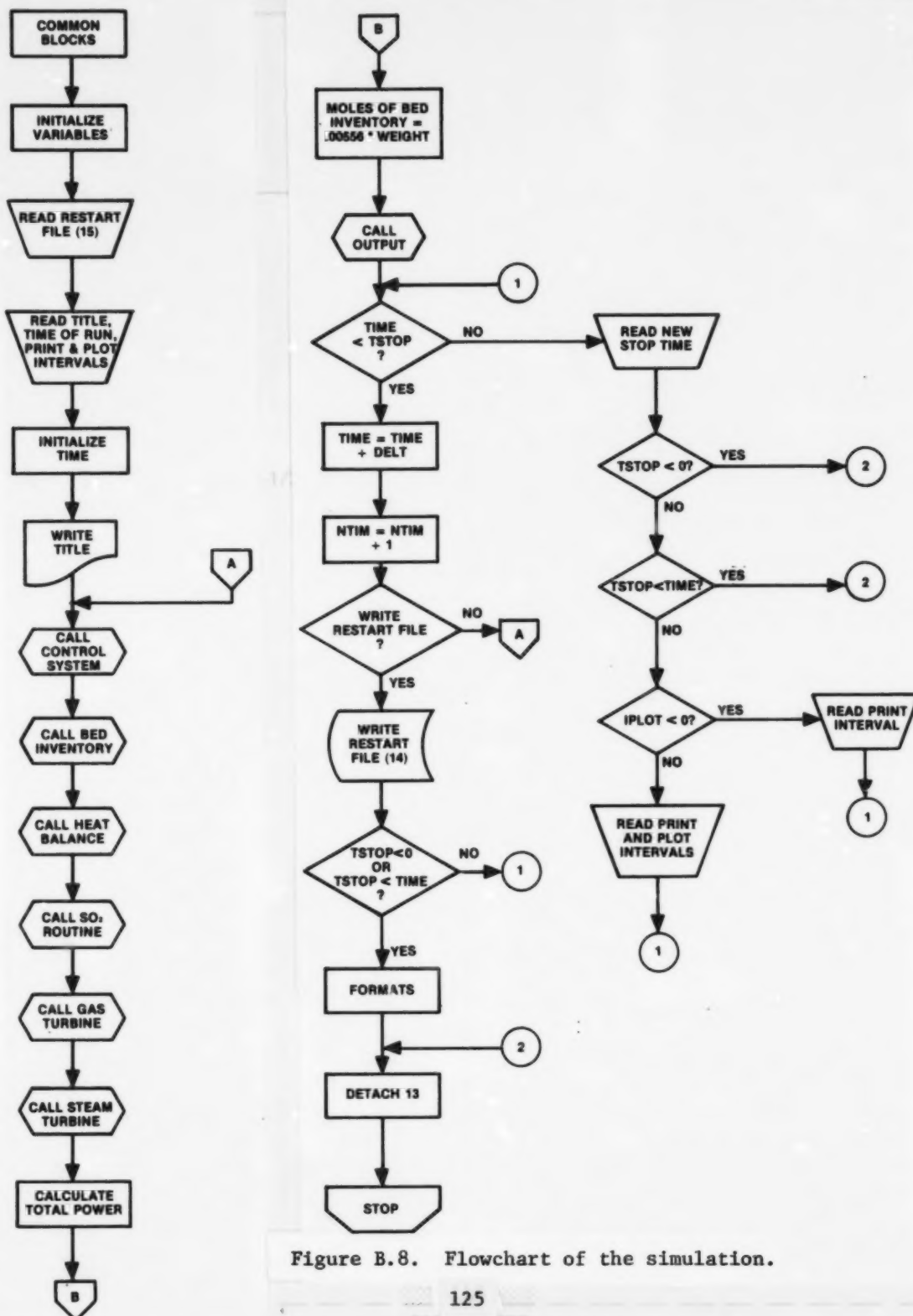


Figure B.8. Flowchart of the simulation.

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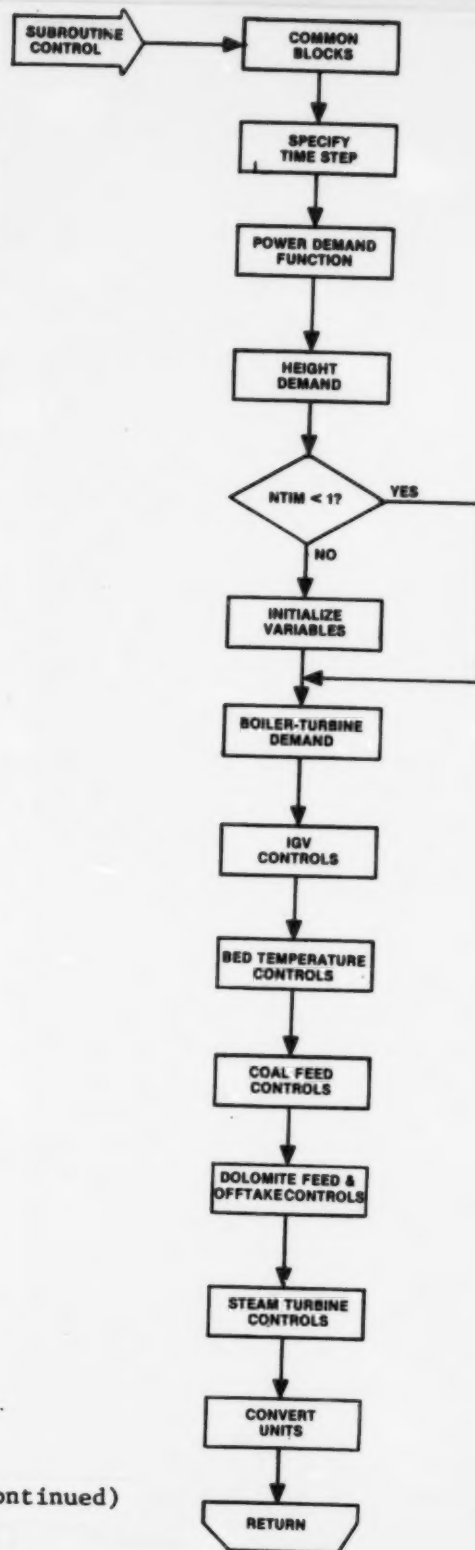
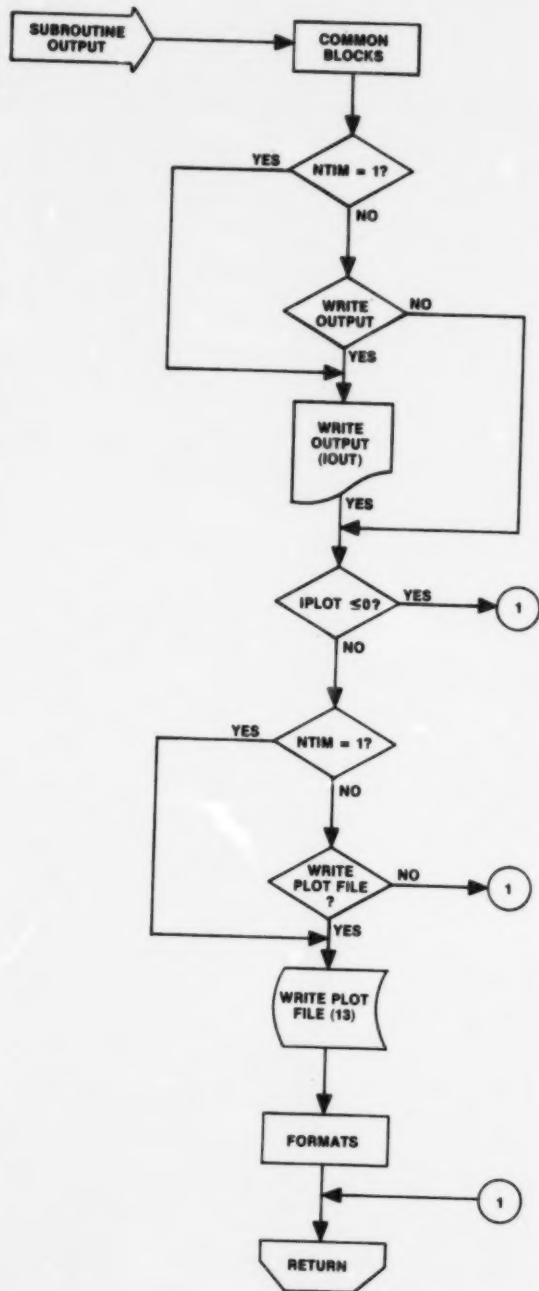


Figure B.8. (Continued)

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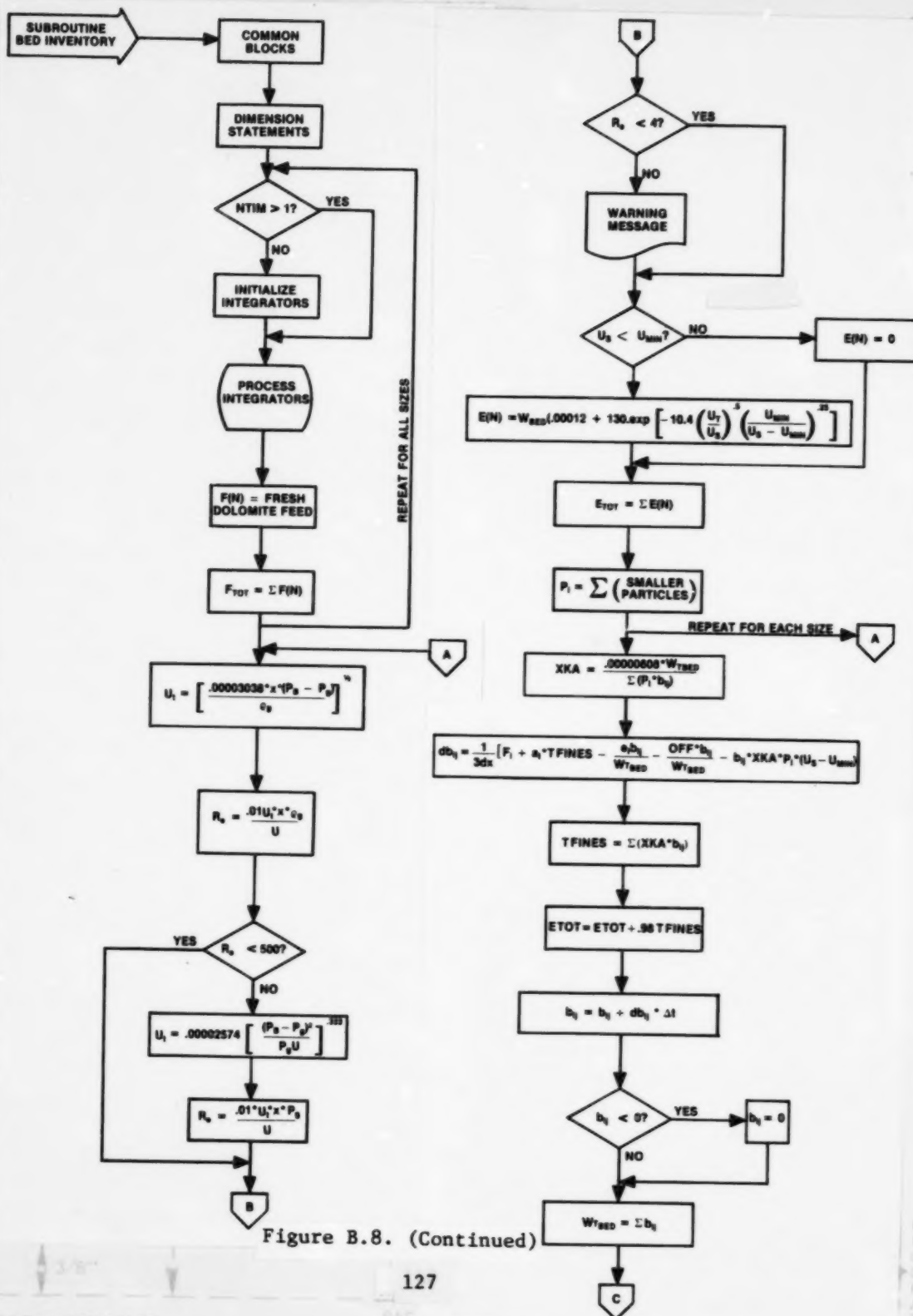


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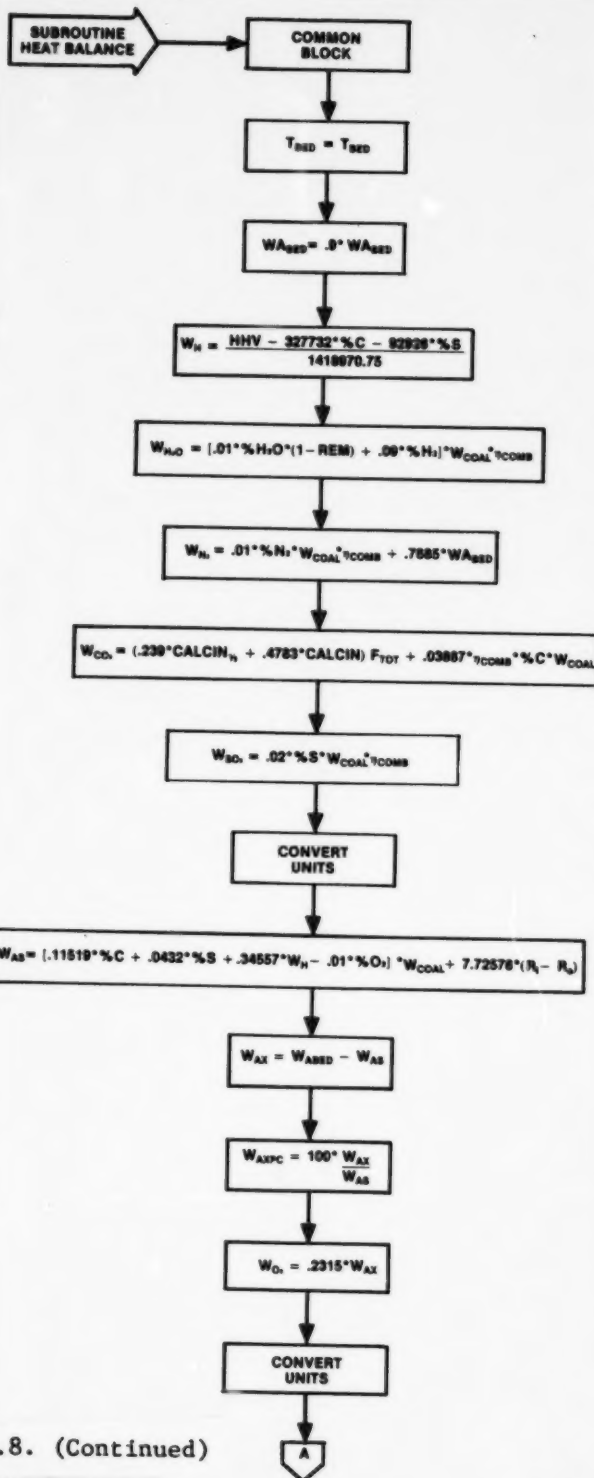
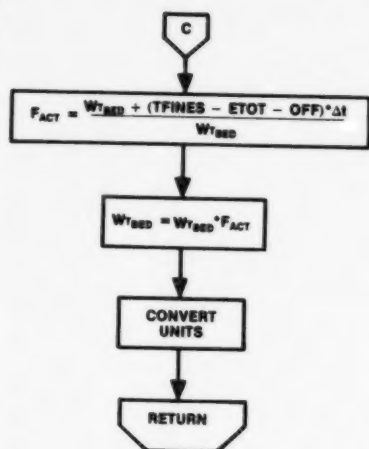


Figure B.8. (Continued)

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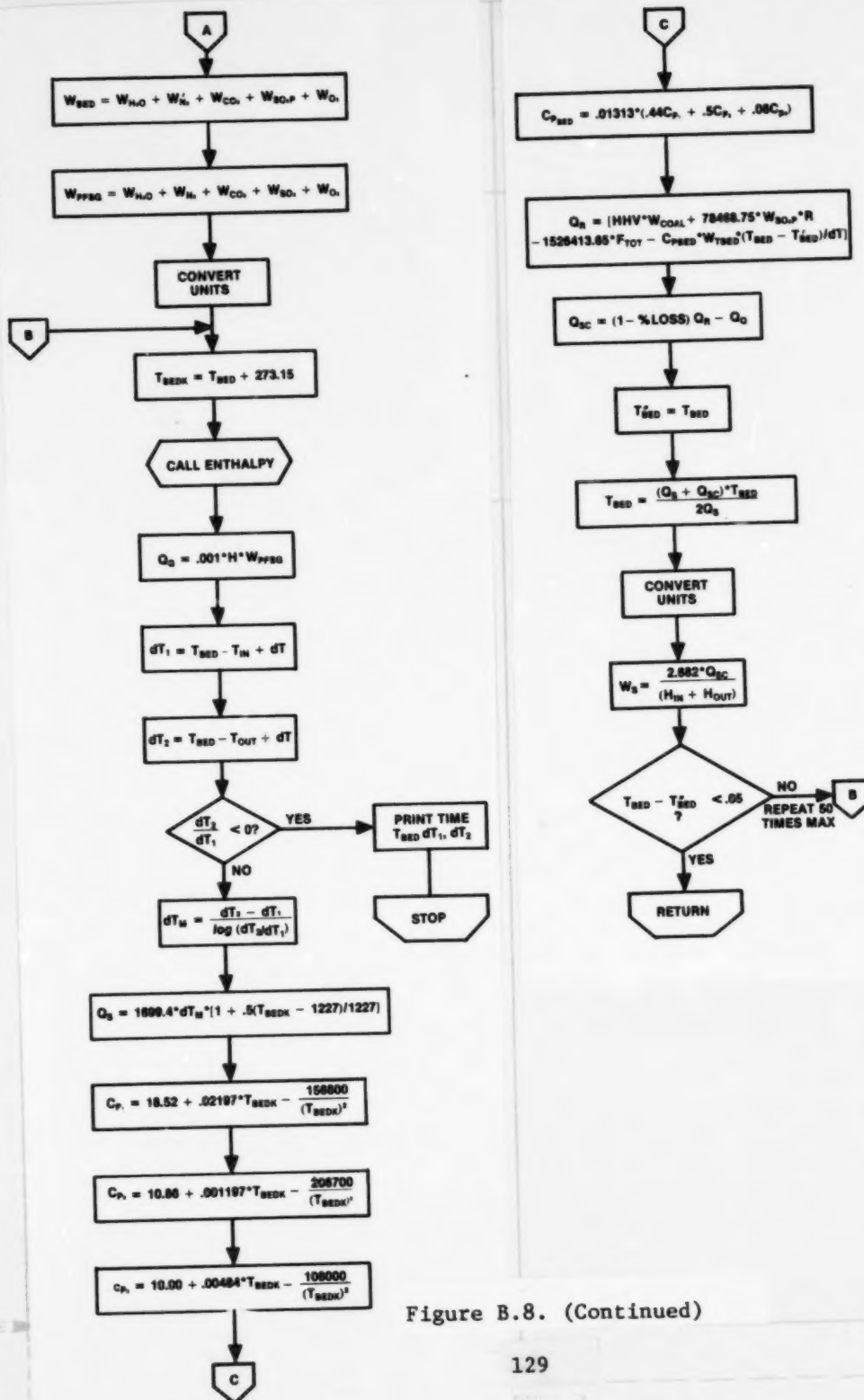


Figure B.8. (Continued)

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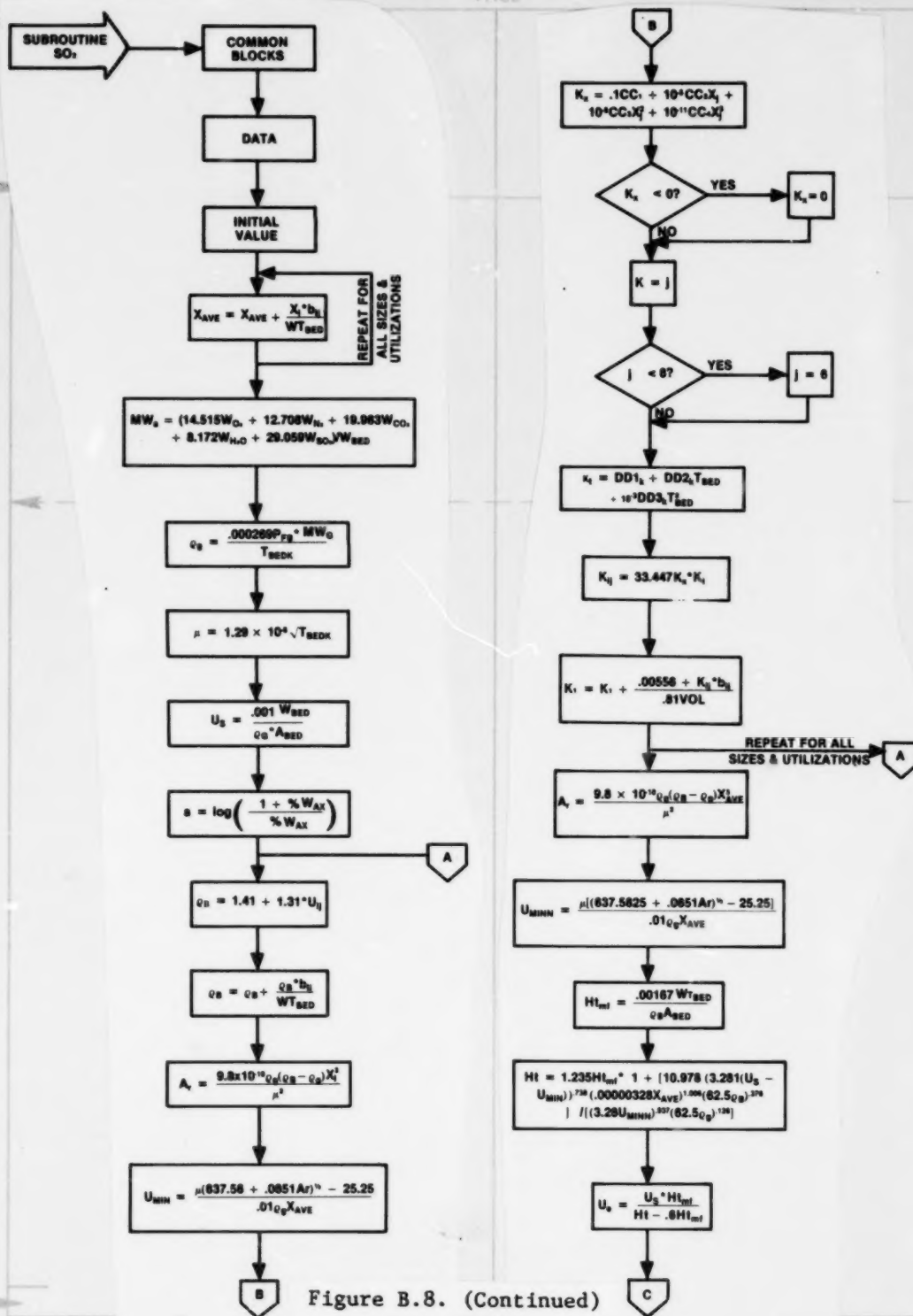
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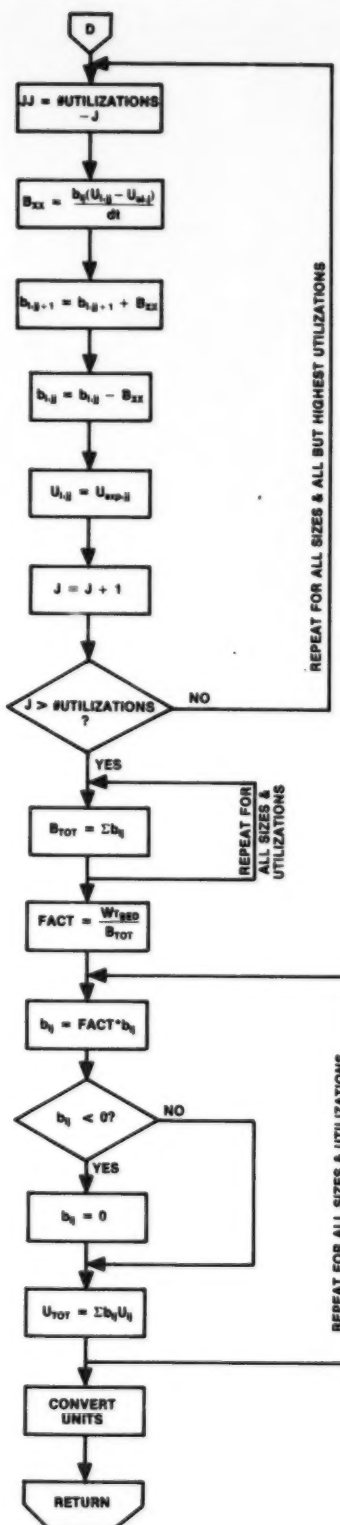
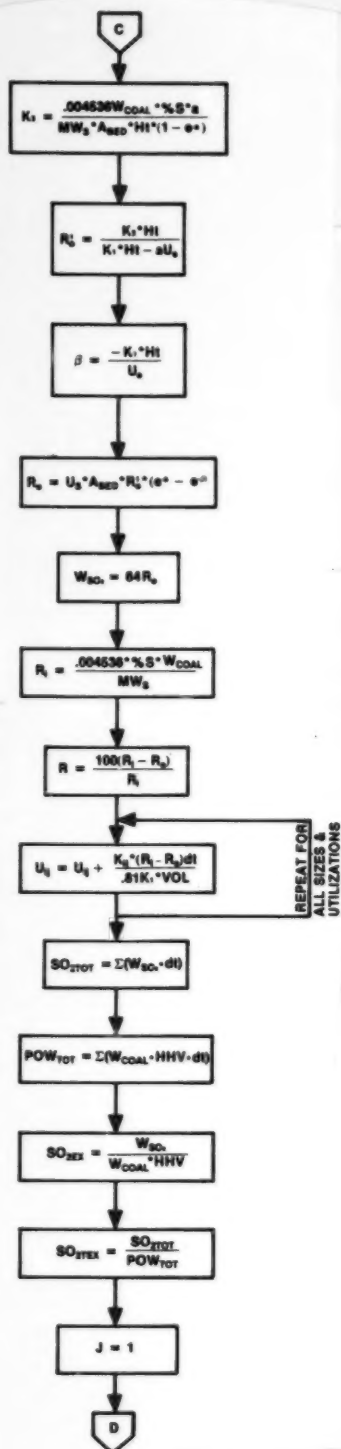


Figure B.8. (Continued)

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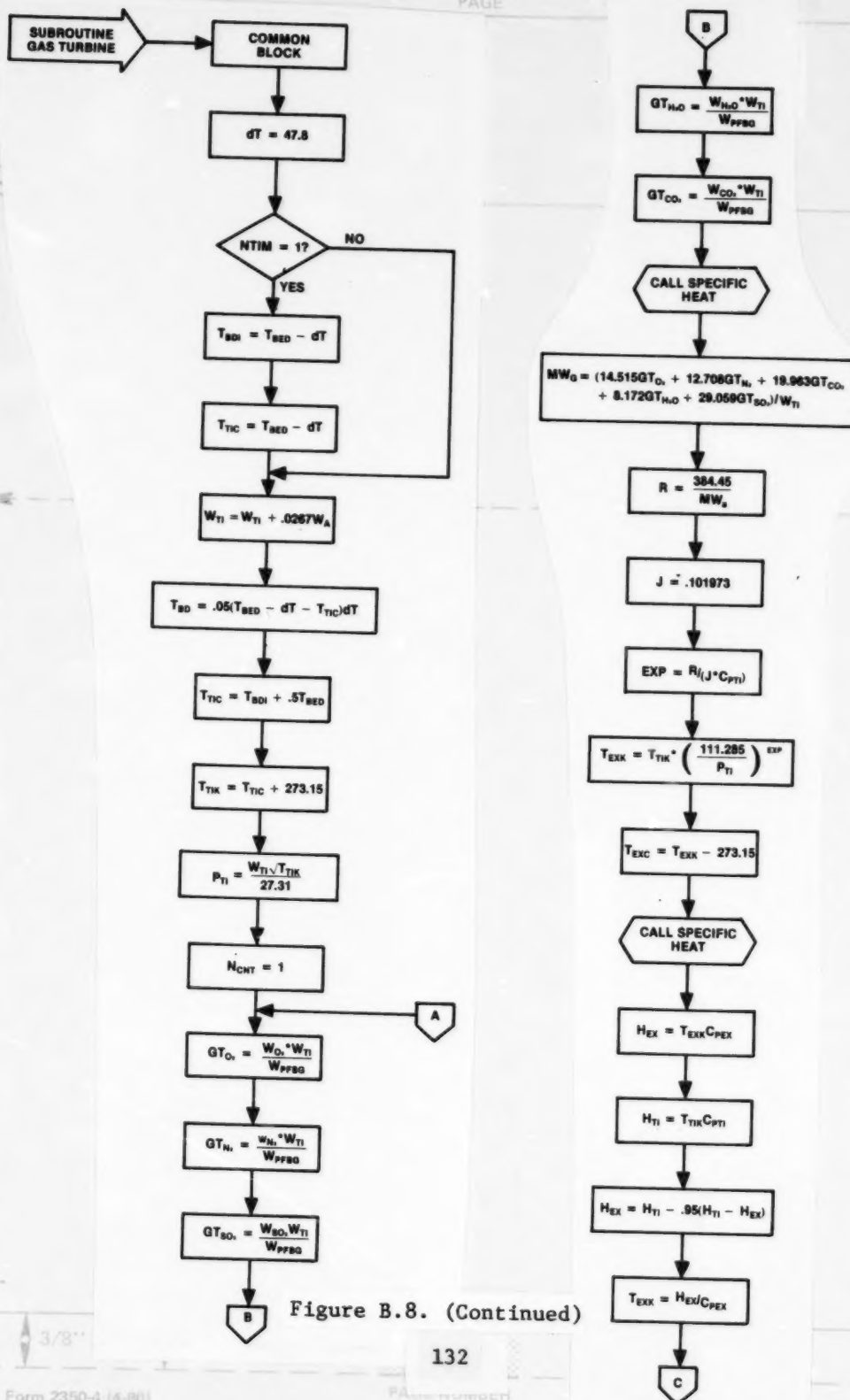


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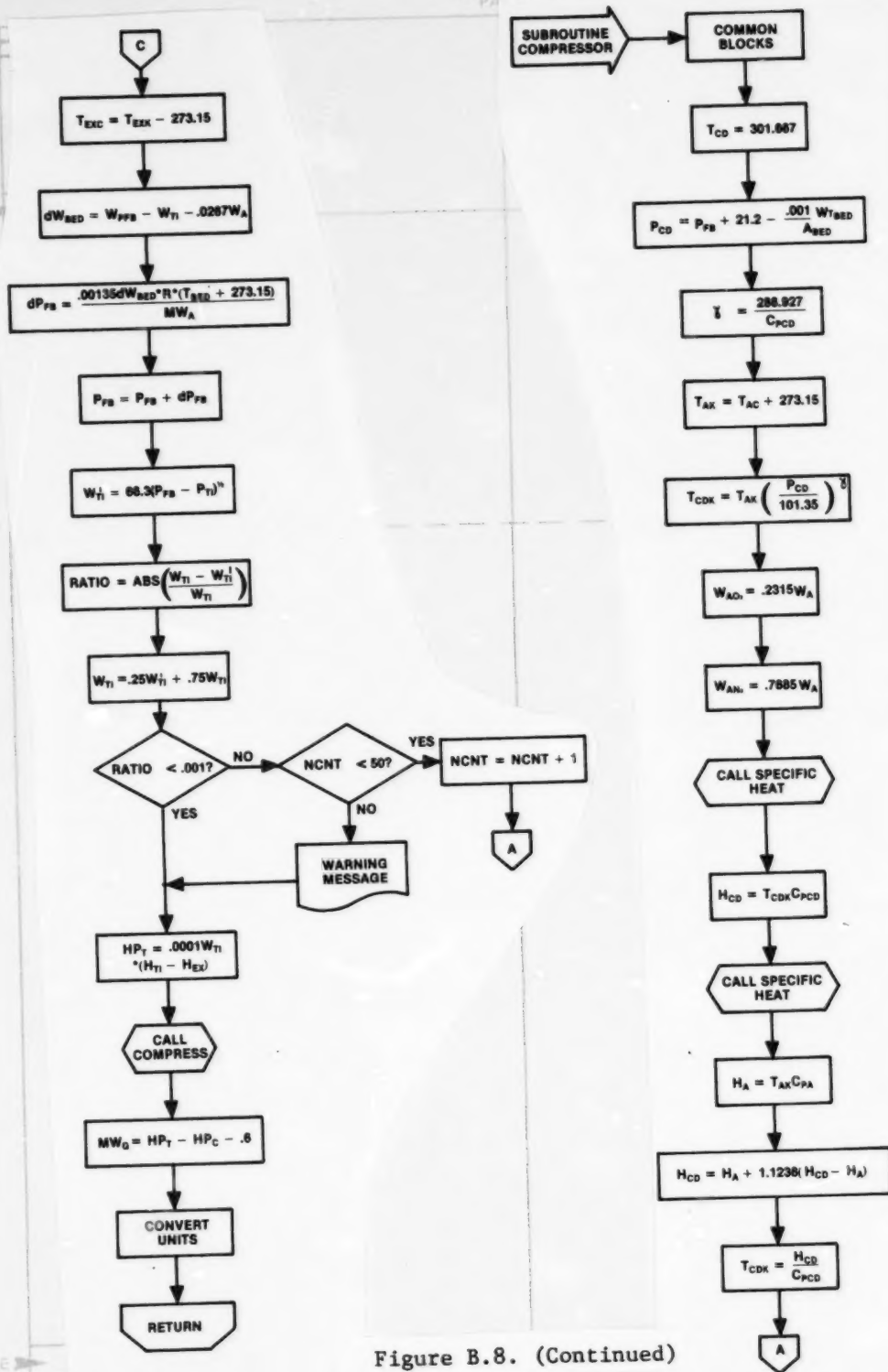


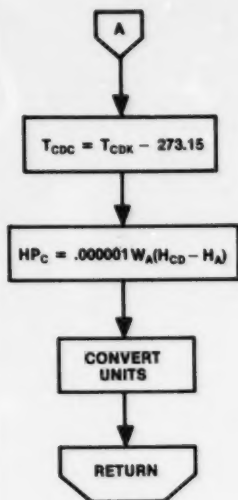
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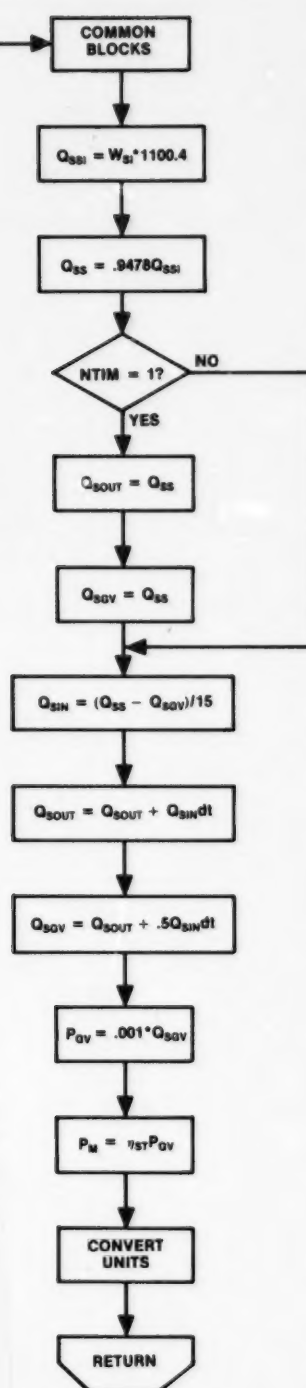
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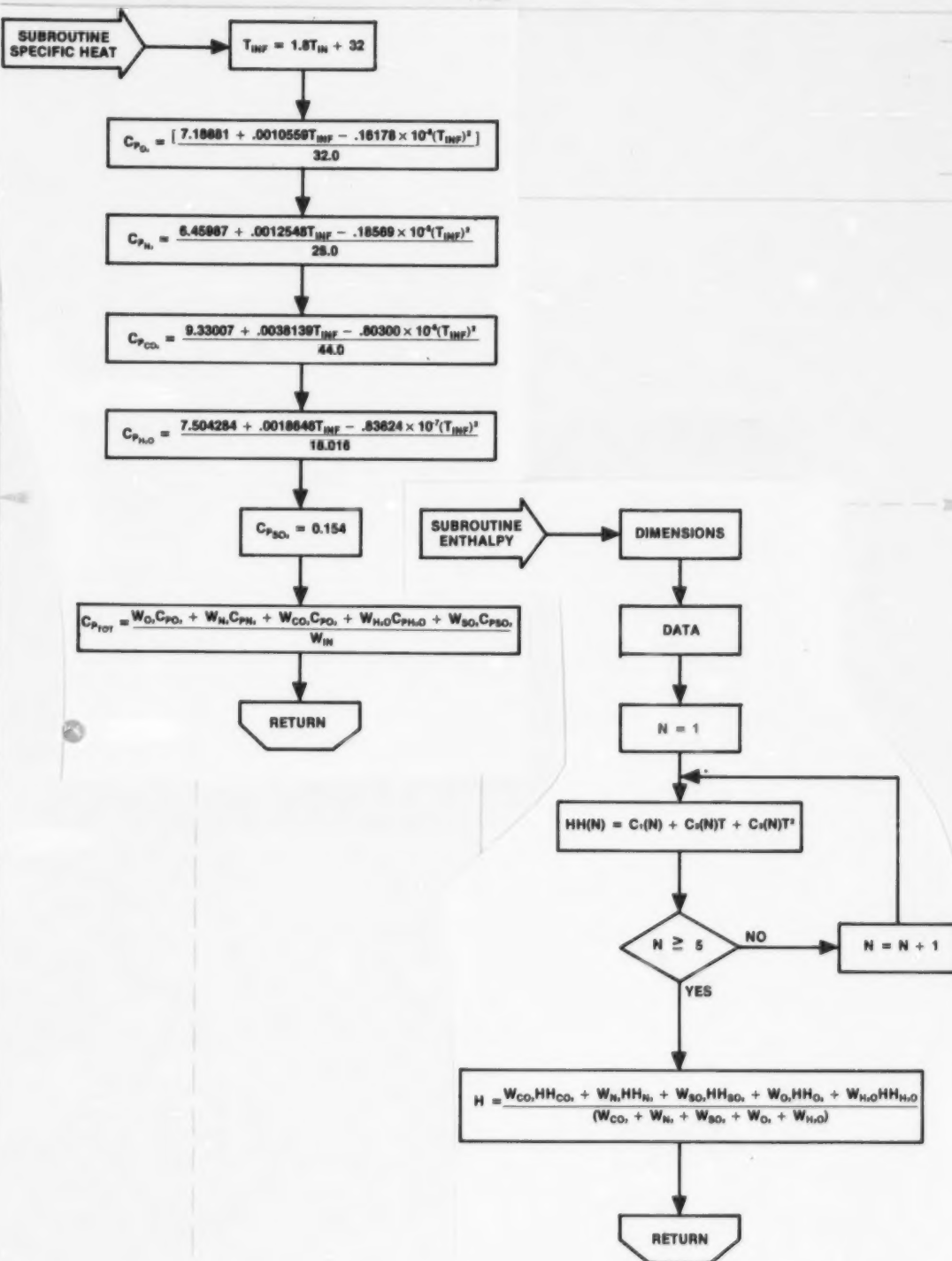


Figure B.8. (Continued)

LISTING OF FEP4/SO2MAIN

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1000C    PROGRAM SO2EMISS
1003C
1006C    DYNAMIC ANALYSIS OF SO2 EMISSIONS FROM
1009C    A PRESSURIZED FLUIDIZED BED
1012C
1015C    DEVELOPED BY GENERAL ELECTRIC COMPANY
1018C    ENERGY SYSTEMS PROGRAMS DEPARTMENT
1021C    SCHENECTADY, NEW YORK 12345
1024C
1027C    EPA CONTRACT NUMBER: 68-02-3131
1030C    NAME: CONSTANT PERCENTAGE SO2 REMOVAL
1033C
1036C    PARAMETER NX=11,NU=10
1039C
1042C    COMMON /SINF0/DELT,TIME,TINIT,TSTOP,IPRNT,IPL0T,NTIM,IOUT,IN
1045C
1048C    COMMON /CONT/WA,WCOAL,WDO1,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
1051C    & COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDO11,OFF1,RETENT,XAVE,XAVE1,
1054C    & UMIN(NX),TOTEFF,SO2TOT,POWTOT,UTOT,DSTDMD,DEMAND
1057C
1060C    COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
1063C    & THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
1066C    & TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
1069C
1072C    COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,RO1,R1,R11,UEXP(NU),
1075C    & XK(NX,NU),ALPHA,XMOLWT(7),SO2EX,SO2EX1,SO2TEX,SO2TEX1,
1078C    & GDENS,GDENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
1081C
1084C    COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WCO2,WCO21,
1087C    & WN2,WN21,W02,W021,WH20,WH201,WS02,WS021,WPFBG,WPFBG1,
1090C    & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
1093C
1096C    COMMON /GTURB/WTI,WTI1,Q0,Q01,PTI,PTI1,TTIC,TTIF,TEXC,TEXF,
1099C    & DPFB,DPFB1,HPT,HPT1,XMW0,XMW01,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
1102C    & HPC1,CPCD1,PRDROP,PRDROP1
1105C
1108C    COMMON/STTURB/WS,WS1,QS,QS1,STMPRSS,POUT,PRROUT,PSOUT,
1111C    & PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
1114C
1117C    CHARACTER DATE*8,TITLE*72(3),PLTFIL*4(3),UNUM*12,CATFILE*22
1120C    CHARACTER COALCOMP*10(7)
1123C
1126C    DIMENSION BUFF(380)
1129C
1132C    DATA IN,IOUT/05,06/
1135C    DATA PLTFIL(3)/4H; /
1138C    DATA TAC/15./
1141C    DATA XMOLWT/5.4432,.4536,6.3504,14.5152,7.2576,8.1648,0./
1144C    DATA CEFF,REM/1.,1./
1147C    DATA CPCD1/1048.4/
1150C    DATA AREABD,VOL/179.49,492.36/
1153C    DATA TIN,TOUT,DT/358.89,540.56,-6.667/
1156C
1159C    STEAM TURBINE CONSTANTS
1162C    DATA TSINC,TSOUTC/537.8,176.7/
1165C    DATA STMPRSS,PRROUT/24129.,4136.4/
1168C    DATA STEFF/.4535/
1171C
1174C    BED INVENTORY DATA
1177C    DATA PCC/2.,2.,4.,7.,10.,12.,15.,18.,18.,10.,2./
1180C    DATA HCALC,TCALC/0.,1./
1183C    DATA A/8*0.,3*.0062/
1186C
1189C    SO2 DATA
1192C    DATA UEXP/.05,.15,.25,.35,.45,.55,.65,.75,.85,.95/
1195C    DATA (U(1,1),I=1,NX)/11*.05/
1198C    DATA (U(1,2),I=1,11)/11*.15/
1201C    DATA (U(1,3),I=1,11)/11*.25/
1204C    DATA (U(1,4),I=1,11)/11*.35/
1207C    DATA (U(1,5),I=1,11)/11*.45/
1210C    DATA (U(1,6),I=1,11)/11*.55/
1213C    DATA (U(1,7),I=1,11)/11*.65/
1216C    DATA (U(1,8),I=1,11)/11*.75/
1219C    DATA (U(1,9),I=1,11)/11*.85/
1222C    DATA (U(1,10),I=1,11)/11*.95/

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Figure B.9. Listing of the computer simulation.

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LISTING (CONT) OF FEP4/302MAIN

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1225C
1228C
1231C READ RESTART DATA FILE
1234C
1237 READ (15,4001) TIME,NTIM
1240 READ (15,4001) COALPC
1243 READ (15,4001) X
1246 READ (15,4001) UMIN
1249 DO 7 J=1,NU
1252 7 READ (15,4001) (B(I,J),I=1,NX)
1255 READ (15,4001) HHV,WTBED,TFINES,ETOT
1258 READ (15,4001) VISC,GDENS,BDENS,UMINN
1261 READ (15,4001) XMWG,PM,PTOT,TOTEFF
1264 READ (15,4001) WCOAL,WCOL,OFF,XIGV
1267 READ (15,4001) CAS,R1,RO,RETENT
1270 READ (15,4001) PCG,PFB,PTI,TBED,TTIC
1273 READ (15,4001) WSO2P,WSO2,SO2EX,SO2TOT,POWTOT
1276 READ (15,4001) BDENS,GDENS,HT,HTMF
1279 READ (15,4001) US,WAS,WAX,WAXPC
1282 READ (15,4001) QR,QG,QS,PGV
1285 READ (15,4001) WBED,WPFBG,WTI
1286 CALL DETACH (15,1STAT, )
1288C
1291 CALL FPARAM (1,135)
1294 CALL USRCOD(UNUM)
1297 NTIM=1
1300C
1303C INPUT
1306C
1309 READ (IN,2000) TITLE(1)
1312 READ (IN,2000) TITLE(2)
1315 READ (IN,2000) TITLE(3)
1318 READ (IN,2001) TINIT,TSTOP
1321 READ (IN,2001) IPRNT,IPLST
1324 IF (IPLST .LE. 0)GO TO 10
1327 READ (IN,2002) PLTFIL(1),PLTFIL(2)
1330 ENCODE (CATFILE,3001)UNUM,'/',PLTFIL(1),PLTFIL(2),' '
1333 CALL FCREAT(CATFILE,1,200,0,3,1STAT,BUFF)
1336 CALL ATTACH (13,PLTFIL,3,0,1STAT, )
1339C
1342C INITIALIZATION
1345C
1348 10 TIME=TINIT
1351 WRITE (IOUT,1005)
1354 WRITE (IOUT,1006) TITLE
1357C
1360C RUN THROUGH SIMULATION
1363C
1366 20 CONTINUE
1369 CALL CONTRL
1372 CALL BEDINV
1375 CALL HEATBAL
1378 CALL SO2
1381 CALL GASTURB
1384 CALL STMTURB
1387C
1390 PTOT=.969*(XMWG+PM)
1393 PTOT1=.969*(XMWG1+PM1)
1396 TOTEFF=1E6*PTOT/(WCOAL*HHV)
1397 DO 23 J=1,NU
1398 DO 23 I=1,NX
1399 23 B(I,J)=.00556*B(I,J)
1400C
1402 ETOT=ETOT+.01*COALPC(7)*WCOAL
1403 ETOT1=2.2046*ETOT
1405 CALL OUTPUT
1408 ETOT=ETOT-.01*COALPC(7)*WCOAL
1409 DO 26 J=1,NU
1410 DO 26 I=1,NX
1411 26 B(I,J)=B(I,J)/.00556
1412C
1414 30 IF(TIME+DELT .LE. TSTOP)GO TO 40
1417 READ (IN,2001) TSTOP
1420 IF (TSTOP .LE. 0.)GO TO 99
1423 IF(TSTOP .LT. TIME)GO TO 99

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Figure B.9. Listing of the computer simulation. (Continued)

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FOR TABLES
AND ILLUS-
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LISTING (CONT) OF FEP4/SO2MAIN

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1428 IF(IPL0T .LE. 0)GO TO 35
1429 READ (IN,2001) IPRNT,IPL0T
1432 GO TO 30
1435 35 CONTINUE
1438 READ (IN,2001)IPRNT
1441 GO TO 30
1444C
1447 40 TIME=TIME+DELT
1450 NTIM=NTIM+1
1453 XTIM=TIME/3600.
1456 INTTIM=TIME/3600
1459 IF(XTIM .NE. INTTIM)GO TO 25
1468C
1471C WRITE RESTART DATA FILE
1474C
1477 WRITE (14,4001) TIME,NTIM
1480 WRITE (14,4001) COALPC
1483 WRITE (14,4001) X
1486 WRITE (14,4001) UMIN
1489 DO 100 J=1,NU
1492 100 WRITE (14,4001) (B(I,J),I=1,NX)
1495 WRITE (14,4001) HHV,WTBED,TFINES,ETOT
1498 WRITE (14,4001) VISC,GDENS,BDENS,UMINN
1501 WRITE (14,4001) XMWG,PM,PTOT,TOTEFF
1504 WRITE (14,4001) WCOAL,WDO1,OFF,XIGV
1507 WRITE (14,4001) CAS,RI,RO,RETENT
1510 WRITE (14,4001) PCD,PFB,PTI,TBED,TTIC
1513 WRITE (14,4001) WS02P,WS02,S02EX,S02TOT,POWTOT
1516 WRITE (14,4001) BDENS,GDENS,HT,HTMF
1519 WRITE (14,4001) US,WAS,WAX,WAXPC
1522 WRITE (14,4001) QR,QG,QS,PGV
1525 WRITE (14,4001) WBED,WPFBG,WTI
1528 REWIND 14
1528 25 GO TO 20
1531C
1534C FORMAT STATEMENTS
1535C
1536 1001 FORMAT(///1X,'ENTER TITLE (3 LINES OF 72 CHARACTERS)')
1537 1002 FORMAT(///1X,'ENTER INITIAL AND STOP TIMES (SECONDS)')
1538 1003 FORMAT(///1X,'ENTER PRINT AND PLOT INTERVALS')
1539 1004 FORMAT(///1X,'ENTER PLOT FILE (8 CHARACTERS MAX)')
1540 1005 FORMAT(////////)
1543 1006 FORMAT(1X,A72)
1544 1007 FORMAT(///1X,'ENTER NEW STOP TIME TO CONTINUE; 0 TO QUIT')
1545 1008 FORMAT(///1X,'ENTER PRINT INTERVAL')
1546C
1549 2000 FORMAT(A72)
1552 2001 FORMAT(V)
1555 2002 FORMAT(2A4)
1558C
1561 3001 FORMAT(A12,A1,A4,A4,A1)
1564C
1567 4001 FORMAT(4(1X,E10.4))
1568C
1569 99 CALL DETACH (13,ISTAT, )
1570 STOP
1573 END
2000 SUBROUTINE OUTPUT
2003C
2006C GENERATES PRINTED OUTPUT AND PLOT FILE
2009C AT APPROPRIATE TINTERVALS
2012C
2015 PARAMETER NX=11,NU=10
2018 COMMON /SINFO/DELT,TIME,TINIT,TSTOP,IPRNT,IPL0T,NTIM,IOUT,IN
2021C
2024 COMMON /CONT/WA,WCOAL,WDO1,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
2027 & COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDO1,OFF1,RETENT,XAVE,XAVE1,
2030 & UMIN(NX),TOTEFF,S02TOT,POWTOT,UTOT,DSTDMD,DEMAND
2033C
2036 COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
2039 & THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
2042 & TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
2045C
2048 COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,RO1,RI,R11,UEXP(NU),
2051 & XK(NX,NU),ALPHA,XHOLWT(7),S02EX,S02EX1,S02TEX,S02TEX1,
2054 & GDENS,GDENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
2057C

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Figure B.9. Listing of the computer simulation. (Continued)

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2060      COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WCO2,WCO21,
2063      & WN2,WN21,W02,W021,WH20,WH201,WS02,WS021,WPFBG,WPFBG1,
2066      & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
2069C
2072      COMMON /GTURB/WT1,WT11,QG,QG1,PT1,PT11,TTIC,TTIF,TEXC,TEXF,
2075      & DPFB,DPFB1,HPT,HPT1,XMWG,XMWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
2078      & HPC1,CPCD1,PRDROP,PRDROP1
2081C
2084      COMMON/STTURB/WS,WS1,QS,QS1,STMPRSS,POUT,PRSOOUT,PSOUT,
2087      & PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
2090C
2093      CHARACTER COALCOMP=15(7)
2096C
2099      DATA COALCOMP/'CARBON', 'HYDROGEN',
2102      & 'NITROGEN', 'SULFUR', 'OXYGEN',
2105      & 'SURFACE WATER', 'ASH', '/'
2108C
2111      IF(NTIM.EQ. 1) GO TO 10
2114      IF(MOD(NTIM-1,IPRNT) .NE. 0)GO TO 20
2117C
2120      10 IF(NTIM.GT. 1) WRITE (IOUT,1000)
2123      WRITE (IOUT,1001) TIME
2126      WRITE (IOUT,1002)
2129      WRITE (IOUT,1003) (COALCOMP(I),COALPC(I),COALMOL(I),I=1,7)
2132      WRITE (IOUT,1100)
2135      WRITE (IOUT,1101) PTOT,PTOT1
2138      WRITE (IOUT,1102) WCOAL,WCOAL1
2141      WRITE (IOUT,1103) WDOL,WDOL1
2144      WRITE (IOUT,1104) WA,WA1
2147      WRITE (IOUT,1105) OFF,OFF1
2150      WRITE (IOUT,1106) HHV,HHV1
2153      WRITE (IOUT,1107) CAS
2156      WRITE (IOUT,1108) XAVE,XAVE1
2159      WRITE (IOUT,1109) RETENT
2162      WRITE (IOUT,1110) PFB,PFB1
2165      WRITE (IOUT,1111) TOTEFF
2168      WRITE (IOUT,1112) UTOT
2171      WRITE (IOUT,1200)
2174      WRITE (IOUT,1201) TFINES,TFINES1
2177      WRITE (IOUT,1202) WTBED,WTBED1
2180      WRITE (IOUT,1203) ETOT,ETOT1
2183      WRITE (IOUT,1204) FTOT,FTOT1
2186      WRITE (IOUT,1300)
2189      WRITE (IOUT,1301) WS02P,WS02P1
2192      WRITE (IOUT,1302) RI
2195      WRITE (IOUT,1303) RO
2198      WRITE (IOUT,1304) GDENS,GDENS1
2201      WRITE (IOUT,1305) BDENS,BDENS1
2204      WRITE (IOUT,1306) HT,HT1
2207      WRITE (IOUT,1307) US,US1
2210      WRITE (IOUT,1308) UEFF,UEFF1
2213      WRITE (IOUT,1309) S02EX,S02EX1
2216      WRITE (IOUT,1310) S02TEX,S02TEX1
2219      WRITE (IOUT,1311) HTMF,HTMF1
2222      WRITE (IOUT,1312) UMINN,UMINN1
2225C
2228      WRITE (IOUT,1400)
2231      WRITE (IOUT,1401) WAS,WAS1
2234      WRITE (IOUT,1402) WAX,WAX1
2237      WRITE (IOUT,1403) QR,QR1
2240      WRITE (IOUT,1404) WAXPC
2243      WRITE (IOUT,1405) WCO2,WCO21
2246      WRITE (IOUT,1406) WN2,WN21
2249      WRITE (IOUT,1407) W02,W021
2252      WRITE (IOUT,1408) WH20,WH201
2255      WRITE (IOUT,1409) WS02,WS021
2258      WRITE (IOUT,1410) WPFBG,WPFBG1
2261      WRITE (IOUT,1411) TBED,TBEDF
2264C
2267      WRITE (IOUT,1500)
2270      WRITE (IOUT,1501) WT1,WT11
2273      WRITE (IOUT,1502) QG,QG1
2276      WRITE (IOUT,1503) PT1,PT11
2279      WRITE (IOUT,1504) TTIC,TTIF
2282      WRITE (IOUT,1505) TEXC,TEXF
2285      WRITE (IOUT,1506) PRDROP,PRDROP1
2288      WRITE (IOUT,1507) HPT,HPT1
2291      WRITE (IOUT,1508) XMWG,XMWG1
2294      WRITE (IOUT,1509) XIGV
2297      WRITE (IOUT,1510) TAC,TAF
2300      WRITE (IOUT,1511) TCDC,TCDF
2303      WRITE (IOUT,1512) PCD,PCD1

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Figure B.9. Listing of the computer simulation. (Continued)


```

2306 WRITE (IOUT,1513) HPC,HPC1
2309C
2312 WRITE (IOUT,1600)
2315 WRITE (IOUT,1601) WS,WS1
2318 WRITE (IOUT,1602) QS,QS1
2321 WRITE (IOUT,1603) STMPRSS,PCUT
2324 WRITE (IOUT,1604) PGV,PGV1
2327 WRITE (IOUT,1605) PH,PH1
2330C
2333 WRITE (IOUT,1700) (X(I),I=1,NX)
2336 DO 15 J=1,NU
2339 15 WRITE (IOUT,1702) (B(I,J),I=1,NX)
2342C PLOT FILE
2345C
2348 20 IF(IPLUT .LE. 0)GO TO 99
2351 IF(NTIM .EQ. 1)GO TO 30
2354 IF(MOD(NTIM-1,IPLUT) .NE. 0)GO TO 99
2357 30 WRITE (13,2001) TIME,PTOT,WCOAL,WDOOL,WA,OFF,CAS,XAVE,RETENT,PFB,
2360 & TFINES,WTBED,ETOT,WSO2P,RO,R1,GDENS,BOENS,HT,US,UEFF,S02EX,
2363 & S02TEX,HTMF,UMINN,QR,WAXPC,WCO2,WN2,W02,WH20,WSO2,TBED,
2366 & WTI,PTI,TTIC,TEXC,HPT,HPC,XMWG,XIGV,PCD,TCDC,WS,GS,PH,UTOT
2369C
2372C FORMAT STATEMENTS
2375C
2378 1000 FORMAT(//////////)
2381 1001 FORMAT(////10X,'TIME = ',F10.1,' SECONDS')
2384 1002 FORMAT(////7X,'COAL COMPOSITION',11X,'WEIGHT %',12X,'MOLE %')
2387 1003 FORMAT(7X,A15,10X,F10.1,8X,F10.4)
2390 1100 FORMAT(//5X,'CONTROL SYSTEM')
2393 1101 FORMAT(7X,'TOTAL POWER',14X,F10.2,' (MW)',4X,F10.2,' (HP)')
2396 1102 FORMAT(7X,'COAL FLOW',16X,F10.2,' (KG/S)',2X,F10.2,' (LB/SEC)')
2399 1103 FORMAT(7X,'DOLOMITE',17X,F10.2,' (KG/S)',2X,F10.2,' (LB/SEC)')
2402 1104 FORMAT(7X,'AIR FLOW',17X,F10.2,' (KG/S)',2X,F10.2,' (LB/SEC)')
2405 1105 FORMAT(7X,'BED OFFTAKE',14X,F10.2,' (KG/S)',2X,F10.2,' (LB/SEC)')
2408 1106 FORMAT(7X,'HIGH HEATING VALUE',7X,F10.1,' (J/KG)',1X,F10.2,
2411 & ' (BTU/LB)')
2414 1107 FORMAT(7X,'CA/S FEED RATIO',10X,F10.4)
2417 1108 FORMAT(7X,'AVE PARTICLE SIZE',8X,F10.4,' (MICRON)',F10.6,' (IN)')
2420 1109 FORMAT(7X,'SULFUR RETENTION',9X,F10.4,' (%)')
2423 1110 FORMAT(7X,'BED PRESSURE',13X,F10.2,' (KPA)',3X,F10.2,' (PSI)')
2426 1111 FORMAT(7X,'PLANT EFFICIENCY',9X,F10.2,' (%)')
2429 1112 FORMAT(7X,'AVERAGE UTILIZATION',6X,F10.2,' (%)')
2432 1200 FORMAT(//5X,'BED INVENTORY')
2435 1201 FORMAT(7X,'TOTAL FINES PRODUCED',5X,F10.3,' (KG/S)',2X,F10.2,
2438 & ' (LB/SEC)')
2441 1202 FORMAT(7X,'BED WEIGHT',15X,F10.1,' (KG)',4X,F10.2,' (LB)')
2444 1203 FORMAT(7X,'ELUTRIATION',14X,F10.2,' (KG/S)',2X,F10.2,' (LB/SEC)')
2447 1204 FORMAT(7X,'FRESH DOLOMITE FEED',6X,F10.2,' (KG/S)',2X,F10.2,
2450 & ' (LB/SEC)')
2453 1300 FORMAT(//5X,'SO2 RELEASE & CAPTURE')
2456 1301 FORMAT(7X,'SO2 PRODUCED',13X,F10.3,' (KG/S)',2X,F10.2,
2459 & ' (LB/SEC)')
2462 1302 FORMAT(7X,'SULFUR ENTERING BED',6X,F10.2,' (MOL/S)')
2465 1303 FORMAT(7X,'SULFUR LEAVING BED',7X,F10.4,' (MOL/S)')
2468 1304 FORMAT(7X,'GAS DENSITY',14X,F10.7,' (G/CC)',2X,F10.4,' (LB/'
2471 & 'CU FT)')
2474 1305 FORMAT(7X,'SOLIDS DENSITY',11X,F10.7,' (G/CC)',2X,F10.4,' (LB/'
2477 & 'CU FT)')
2480 1306 FORMAT(7X,'BED HEIGHT',15X,F10.3,' (M)',5X,F10.3,' (FT)')
2483 1307 FORMAT(7X,'SUPERFICIAL VELOCITY',5X,F10.2,' (M/S)',3X,F10.2,
2486 & ' (FT/SEC)')
2489 1308 FORMAT(7X,'EFFECTIVE VELOCITY',7X,F10.2,' (M/S)',3X,F10.2,
2492 & ' (FT/SEC)')
2495 1309 FORMAT(7X,'SO2 EMISSIONS',12X,E10.4,' (KG/J)',2X,
2498 & ' E10.4,' (LB/BTU)')
2501 1310 FORMAT(7X,'TOTAL SO2 EMISS',10X,E10.4,' (KG/J)',2X,E10.4,' (LB/'
2504 & 'BTU)')
2507 1311 FORMAT(7X,'MINIMUM BED HEIGHT',7X,F10.4,' (M)',4X,F10.2,' (FT)')
2510 1312 FORMAT(7X,'MIN FLUIDIZING VELOCITY',2X,F10.4,' (M/S)',2X,F10.4,
2513 & ' (FT/SEC)')
2516C
2519 1400 FORMAT(//////////5X,'HEAT BALANCE')
2522 1401 FORMAT(7X,'STOICHIOMETRIC AIR FLOW',2X,F10.2,' (KG/S)',2X,F10.2,
2525 & ' (LB/SEC)')
2528 1402 FORMAT(7X,'EXCESS AIR',15X,F10.2,' (KG/S)',2X,F10.2,' (LB/SEC)')
2531 1403 FORMAT(7X,'HEAT OF REACTION',7X,F12.0,' (KW)',2X,F12.0,' (HP)')
2534 1404 FORMAT(7X,'EXCESS AIR FLOW',10X,F10.3,' (%)')
2537 1405 FORMAT(7X,'CO2 RELEASED',13X,F10.3,' (KG/S)',2X,F10.2,' (LB/SEC)')
2540 1406 FORMAT(7X,'N2 RELEASED',14X,F10.3,' (KG/S)',2X,F10.2,' (LB/SEC)')
2543 1407 FORMAT(7X,'O2 RELEASED',14X,F10.3,' (KG/S)',2X,F10.2,' (LB/SEC)')

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Figure B.9. Listing of the computer simulation. (Continued)

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2546 1408 FORMAT(7X,'H2O RELEASED',13X,F10.3,' (KG/S)',2X,F10.2,' (LB/SEC)')
2549 1409 FORMAT(7X,'SO2 RELEASED',13X,F10.3,' (KG/S)',2X,F10.2,' (LB/SEC)')
2552 1410 FORMAT(7X,'BED OUTLET GAS FLOW',6X,F10.2,' (KG/S)',
2555 & '2X,F10.2,' (LB/SEC)')
2558 1411 FORMAT(7X,'BED TEMPERATURE',10X,F10.2,' (DEG C)',1X,F10.2,
2561 & ' (DEG F)')
2564C
2567 1500 FORMAT(//5X,'GAS TURBINE & AIR COMPRESSOR')
2570 1501 FORMAT(7X,'TURBINE INLET FLOW',7X,F10.3,' (KG/S)',2X,F10.3,
2573 & ' (LB/SEC)')
2576 1502 FORMAT(7X,'PFB EXHAUST HEAT',7X,F12.0,' (KW)',1X,F12.0,
2579 & ' (HP)')
2582 1503 FORMAT(7X,'TURBINE INLET PRESSURE',3X,F10.3,' (KPA)',3X,F10.3,
2585 & ' (PSI)')
2588 1504 FORMAT(7X,'TURBINE INLET TEMPERATURE',F10.3,' (DEG C)',1X,F10.3,
2591 & ' (DEG F)')
2594 1505 FORMAT(7X,'TURBINE EXIT TEMPERATURE',1X,F10.3,' (DEG C)',1X,F10.3,
2597 & ' (DEG F)')
2600 1506 FORMAT(7X,'PRESSURE DROP FROM BED',3X,F10.4,' (KPA)',3X,F10.3,
2603 & ' (PSI)')
2606 1507 FORMAT(7X,'TURBINE POWER (GROSS)',4X,F10.2,' (MW)',4X,F10.2,
2609 & ' (HP)')
2612 1508 FORMAT(7X,'TURBINE POWER (NET)',6X,F10.2,' (MW)',4X,F10.2,
2615 & ' (HP)')
2618 1509 FORMAT(7X,'IGV SETTING (% OPEN)',5X,F10.4)
2621 1510 FORMAT(7X,'AMBIENT TEMPERATURE',6X,F10.2,' (DEG C)',1X,F10.2,
2624 & ' (DEG F)')
2627 1511 FORMAT(7X,'COMPRESS DISCHARGE TEMP',2X,F10.2,' (DEG C)',1X,F10.2,
2630 & ' (DEG F)')
2633 1512 FORMAT(7X,'COMPRESS DISCHARGE PRESS',1X,F10.2,' (KPA)',3X,F10.2,
2636 & ' (PSI)')
2639 1513 FORMAT(7X,'COMPRESS POWER',11X,F10.2,' (MW)',4X,F10.2,' (HP)')
2642C
2645 1600 FORMAT(//5X,'STEAM TURBINE')
2648 1601 FORMAT(7X,'INLET FLOW',15X,F10.2,' (KG/S)',2X,F10.2,' (LB/SEC)')
2651 1602 FORMAT(7X,'INLET HEAT',13X,F12.0,' (KW)',2X,F12.0,' (HP)')
2654 1603 FORMAT(7X,'INLET PRESSURE',11X,F10.3,' (KPA)',3X,F10.3,' (PSI)')
2657 1604 FORMAT(7X,'INLET POWER',14X,F10.2,' (MW)',4X,
2660 & F10.2,' (HP)')
2663 1605 FORMAT(7X,'OUTLET POWER',13X,F10.2,' (MW)',4X,
2666 & F10.2,' (HP)')
2669C
2672 1700 FORMAT(////5X,'SIZE, WEIGHT'///11(1X,F10.2)/)
2675 1702 FORMAT(11(1X,F10.1))
2678C
2681C
2684 2001 FORMAT(V)
2687C
2690C
2693 99 RETURN
2696 END
3000 SUBROUTINE CONTROL
3003C
3006C POWER PLANT AND SO2 EMISSIONS CONTROLS
3009C
3012C
3015 PARAMETER NX=11,NU=10
3018C
3021 COMMON /SINFO/DELT,TIME,TINIT,TSTOP,IPRNT,IPLGT,NTIM,IOUT,IN
3024C
3027 COMMON /CONT/WA,WCOAL,WDOL,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
3030 & COALMOL(7),HHV1,CAS,WAI,WCOAL1,WDOL1,OFF1,RETENT,XAVE,XAVE1,
3033 & UMIN(NX),TOTEFF,SO2TOT,POWTOT,UTOT,DSTOMD,DEMAND
3036C
3039 COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
3042 & THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
3045 & TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
3048C
3051 COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,RO1,RI,R11,UEXP(NU),
3054 & XK(NX,NU),ALPHA,XMOLWT(7),SO2EX,SO2EX1,SO2TEX,SO2TEX1,
3057 & GDENS,GDENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
3060C
3063 COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WCO2,WCO21,
3066 & WN2,WN21,WQ2,WQ21,WH20,WH201,WSO2,WSO21,WPFBG,WPFBG1,
3069 & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WSO2P,WSO2P1
3072C
3075 COMMON /GTURB/WT1,WT11,QG,QG1,PT1,PT11,TTIC,TTIF,TEXC,TEFF,
3078 & DPFB,DPFB1,HPT,HPT1,XHWG,XHWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
3081 & HPC1,CPCD1,PRDROP,PRDROP1
3084C
3087 COMMON/STTURB/WS,WS1,QS,QS1,STMPRSS,POUT,PRSOOT,PSOOT,
3090 & PGV,PGV1,PH,PH1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
3093C

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Figure B.9. Listing of the computer simulation. (Continued)

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3096C
3099C      INITIALIZATION
3102C
3105      DELT=5.
3108      DEMAND=549.1
3111      IF (TIME .GE. 180. .AND. TIME .LE. 480.) DEMAND=
3114      & 549.1+.323*(TIME-180.)
3117      IF (TIME .GT. 480.) DEMAND=646.
3120      HTDMD=2.743
3123C
3126      IF (NTIM .GT. 1)GO TO 5
3129      BD=493.
3132      X12=XIGV
3135      XIGVDM=XIGV
3138      TGAS=TBED
3141      TGI=TBED
3144      CD=WCOAL
3147      COALDMD=WCOAL
3150      WC=WCOAL
3153      WD=WDOL
3156      DO=OFF
3159      OFFDMD=OFF
3162      S2=40.*BLRDMD
3165      SS2=0.
3168      DSTDMD=0.
3171      5 CONTINUE
3174C
3177C      COORDINATED BOILER-TURBINE CONTROL
3180C
3183      STDMD=DEMAND-XMWG
3186      DSTD=STDMD-PM
3189      BD=BD+.17*DELT*DSTD
3192      BB=BD+.085*DELT*DSTD
3195      BLRDMD=BB+.55*DSTD
3198C
3201C      IVG SETTING CONTROL
3204C
3207      DI=.00203*BLRDMD
3210      X11=.05*(DI-XIGVDM)
3213      X12=X12+X11*DELT
3216      XIGVDM=X12+.5*X11*DELT
3219      IF(XIGVDM .LE. .834) XIGV=.57
3222      IF(XIGVDM .GE. 1.0) XIGV=.9994
3225      IF(XIGVDM .GT. .834 .AND. XIGVDM .LT. 1.0) XIGV=.57
3228      & +2.5867*(XIGVDM-.834)
3231      WA=660.*XIGV
3234C
3237C      BED TEMPERATURE PROGRAMMING
3240C
3243      TB=XIGVDM
3246      IF(TB .LE. .51) SPTBED=760.
3249      IF(TB .GT. .51 .AND. TB .LE. .834) SPTBED=760.+
3252      & 377.22*(TB-.51)
3255      IF(TB .GT. .834 .AND. TB .LT. 1.0) SPTBED=882.22
3258      & +435.074*(TB-.834)
3261      IF(TB .GE. 1.0) SPTBED=954.444
3264      TGI=TGI+DELT*.1*(TBED-TGAS)
3267      TGAS=TGI+.05*DELT*(TBED-TGAS)
3270      ERTBED=SPTBED-TGAS
3273C
3276C      COAL FEED CONTROLLER
3279C
3282      CD=CD+.01306*DELT*ERTBED
3285      CDD=CD+.00653*ERTBED
3288      COALDMD=CDD+.2612*ERTBED
3291      WC=WC+.05*DELT*(COALDMD-WCOAL)
3294      WCOAL=WC+.025*DELT*(COALDMD-WCOAL)
3297C
3300C      DOLOMITE FEED CONTROL
3303C
3306      DOLODMD=.337*WCOAL
3309      WD=WD+.05*DELT*(DOLODMD-WDOL)
3312      WDOL=WD+.025*DELT*(DOLODMD-WDOL)
3315C
3318C      OFFTAKE CONTROLLER
3321C
3324      DO=DO+.05*DELT*(.7*DOLODMD-OFFDMD)
3327      OFFDMD=DO+.025*DELT*(.7*DOLODMD-OFFDMD)
3330      OFFREG=-21.713066*(HTDMD-HT)
3333      OFF=OFFREG+OFFDMD
3336      IF (OFF .LT. 0.) OFF=0.
3339C

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Figure B.9. Listing of the computer simulation. (Continued)

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3342C STEAM TURBINE CONTROLS
3345C
3346 S1=DELT*(BLRDMD-.025*S3)
3351 S2=S2+S1
3354 S3=S2+.5*S1
3357 SS1=.1*DELT*(S3-DSTDMD)
3360 SS2=SS2+SS1
3363 DSTDMD=SS2+.5*SS1
3366C
3369C
3372C
3375C CONVERT UNITS
3378C
3381 HHV1=.00043*HHV
3384 WA1=2.2046*WA
3387 WCOAL1=2.2046*WCOAL
3390 WDOL1=2.2046*WDOL
3393 OFF1=2.2046*OFF
3396 CAS=17.203*WDOL/(WCOAL*COALPC(4))
3399C
3402C CALCULATE MOLE PERCENTAGES
3405C
3408 CM=0.
3411 DO 10 M=1,5
3414 COALMOL(M)=COALPC(M)/XMOLWT(M)
3417 10 CM=CM+COALMOL(M)
3420 DO 20 M=1,5
3423 20 COALMOL(M)=100.*COALMOL(M)/CM
3426C
3429C
3432 RETURN
3435 END
4000 SUBROUTINE S02
4003C
4006C S02 RETENTION CALCULATION
4009C
4012 PARAMETER NX=11,NU=10
4015C
4018 COMMON /SINF0/DELT,TIME,TINIT,TSTOP,IPRNT,IPL0T,NTIM,IOUT,IN
4021C
4024 COMMON /CONT/WA,WCOAL,WDOL,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
4027 & COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDOL1,OFF1,RETENT,XAVE,XAVE1,
4030 & UMIN(NX),TOTEFF,S02TOT,POWTOT,UTOT,DSTDMD
4033C
4036 COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
4039 & THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
4042 & TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
4045C
4048 COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,RO1,R1,R11,UEXP(NU),
4051 & XK(NX,NU),ALPHA,XMOLWT(7),S02EX,S02EX1,S02TEX,S02TEX1,
4054 & GDENS,GDENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
4057C
4060 COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WC02,WC021,
4063 & WN2,WN21,W02,W021,WH2O,WH2O1,WS02,WS021,WPFBG,WPFBG1,
4066 & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
4069C
4072 COMMON /GTURB/WT1,WT11,QG,QG1,PT1,PT11,TT1C,TT1F,TEXC,TEXF,
4075 & DPFB,DPFB1,HPT,HPT1,XMWG,XMWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
4078 & HPC1,CPCD1,PRDROP,PRDROP1
4081C
4084 COMMON/STTURB/WS,WS1,QS,QS1,STMPRSS,POUT,PRROUT,PSOUT,
4087 & PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
4090C
4093 DIMENSION CC1(10),CC2(10),CC3(10),CC4(10)
4096 DIMENSION DD1(6),DD2(6),DD3(6)
4099C
4102C
4105 DATA (CC1(K),K=1,10)/2.155,1.504,1.404,1.308,1.166,.878,
4108 & .460,.124,.0098,.0/
4111 DATA (CC2(K),K=1,10)/-1.876,2.253,6.971,-1.864,-3.178,
4114 & -2.124,5.021,6.424,.137,.0/
4117 DATA (CC3(K),K=1,10)/-5.788,-8.420,-17.010,-6.790,-5.442,
4120 & -4.978,-10.799,-10.163,-.285,.0/
4123 DATA (CC4(K),K=1,10)/1.527,2.208,5.092,2.303,2.069,1.896,
4126 & 3.451,3.183,.0092,.0/
4129 DATA (DD1(K),K=1,6)/-11.193,-71.119,-64.425,-124.61,
4132 & -129.76,9.9785/
4135 DATA (DD2(K),K=1,6)/.02075,.1561,.1434,.2775,.2907,-.01813/
4138 DATA (DD3(K),K=1,6)/-.8336,-8.441,-7.840,-15.278,-16.112,.9131/
4141C
4144C
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Figure B.9. Listing of the computer simulation. (Continued)

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4147 HTMF=0.
4150 HT=0.
4153 XK1=0.
4156 BDENS=0.
4159 TBEDK=TBED+273.15
4162C
4165 XAVE=0.
4168 DO 5 M=1,NU
4171 DO 5 N=1,NX
4174 5 XAVE=XAVE+X(N)*B(N,M)/WTBED
4177 XAVE1=.3936E-4*XAVE
4180C
4183C GAS PROPERTIES
4186C
4189 XMWT=(14.515*WC2+12.708*WN2+19.963*WC2+8.172*WH2O+29.059
4192 & WSO2)/WBED
4195 GDENS=.000269*PFB*XMWT/TBEDK
4198 VISC=1.285E-6*SQR(TBEDK)
4201 US=.001*WBED/(GDENS*AREABD)
4204 ALPHA=ALOG((1+.01*WAXPC)/(.01*WAXPC))
4207C
4210C CONDITIONS IN EACH BUCKET
4213C
4216 DO 10 J=1,NU
4219 DO 10 I=1,NX
4222 BDENS1=1.41+1.31*U(I,J)
4225 BDENS=BDENS+BDENS1*B(I,J)/WTBED
4228 ARNO=9.8E-10*GDENS*(BDENS1-GDENS)*X(I)**3/(VISC*VISC)
4231 UMIN(I)=VISC*(SQR(637.5625+.0651*ARNO)-25.25)/(.01*GDENS*X(I))
4234 XKX=.1*CC1(J)+1.E-5*CC2(J)*X(I)+1.E-8*CC3(J)*X(I)*X(I)
4237 & +1.E-11*CC4(J)*X(I)**3
4240 IF (XKX .LT. 0.) XKX=0.
4243 K=J
4246 IF(J .GE. 6) K=6
4249 XKT=DD1(K)+DD2(K)*TBED+1.E-5*DD3(K)*TBED*TBED
4252 XK(I,J)=33.447*XKX*XKT
4255 XK1=XK1+.00556*XK(I,J)*B(I,J)/(.81*VOL)
4258 10 CONTINUE
4261C
4264 ARNO=9.80E-10*GDENS*(BDENS-GDENS)*XAVE**3/(VISC*VISC)
4267 UMINN=VISC*(SQR(637.5625+.0651*ARNO)-25.25)/(.01*GDENS*XAVE)
4270 HTMF=.00167*WBED/(BDENS*AREABD)
4273 HT=1.235*HTMF*(1.+(10.978*(3.281*(US-UMINN))**.738*(.00000328*
4276 & XAVE)**1.006*(62.5*BDENS)**.376)/((3.28*UMINN)**.937*(62.5*
4279 & GDENS)**.126))
4282C
4285C TOTAL BED CONDITIONS
4288C
4291 UEFF=US*HTMF/(HT-.6*HTMF)
4294 XK2=.004536*WCOAL*COALPC(4)*ALPHA/(XMOLWT(4)*AREABD*HT*
4297 & (1-EXP(-ALPHA)))
4300 RO1=XK2*HT/(XK1*HT-ALPHA*UEFF)
4303 BETA=-XK1*HT/UEFF
4306 RO=US*AREABD*RO1*(EXP(-ALPHA)-EXP(BETA))
4309 WSO2=64.*RO
4312 WSO21=2.2046*WSO2
4315 RI=.004536*COALPC(4)*WCOAL/XMOLWT(4)
4318 RETENT=100.*(RI-RO)/RI
4321C
4324C UPDATE UTILIZATIONS
4327C
4330 DO 15 I=1,NX
4333 DO 15 J=1,NU
4336 U(I,J)=U(I,J)+DELT*XK(I,J)*(RI-RO)/(.81*XK1*VOL)
4339 15 CONTINUE
4342 SO2TOT=SO2TOT+WSO2*DELT
4345 POWTOT=POWTOT+WCOAL*HHV*DELT
4348 SO2EX=WSO2/(WCOAL*HHV)
4351 SO2TEX=SO2TOT/POWTOT
4354 20 CONTINUE
4357C
4360C CHANGE UTILIZATIONS HERE
4363C
4366 DO 30 I=1,NX
4369 DO 30 J=1,NU-1
4372 JJ=NU-J
4375 BXX=10*B(I,JJ)*(U(I,JJ)-UEXP(JJ))
4378 B(I,JJ+1)=B(I,JJ+1)+BXX
4381 B(I,JJ)=B(I,JJ)-BXX
4384 U(I,JJ)=UEXP(JJ)
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Figure B.9. Listing of the computer simulation. (Continued)

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4387 30 CONTINUE
4390 BTOT=0.
4393 DO 40 J=1,NU
4396 DO 40 I=1,NX
4399 40 BTOT=BTOT+B(I,J)
4402 FACT=WTBED/BTOT
4405 UTOT=0.
4408 DO 50 J=1,NU
4411 DO 50 I=1,NX
4414 B(I,J)=B(I,J)*FACT
4417 IF (B(I,J).LT.0.) B(I,J)=0.
4420 50 UTOT=UTOT+B(I,J)*U(I,J)
4423 UTOT=100.*UTOT/WTBED
4426C
4429C CONVERT TO U.S. UNITS
4432C
4435 GDENS1=62.43*GDENS
4438 BDENS1=62.43*BDENS
4441 US1=3.281*US
4444 UMINN1=3.281*UMINN
4447 UEFF1=3.281*UEFF
4450 HTMF1=3.281*HTMF
4453 HT1=3.281*HT
4456 R01=2.2046*R0
4459 R11=2.2046*R1
4462 S02EX1=2325.*S02EX
4465 S02TEX1=2325.*S02TEX
4468 RETURN
4471 END
6000 SUBROUTINE HEATBAL
6003C
6006C HEAT & MASS BALANCE OF PFB
6009C
6012 PARAMETER NX=11,NU=10
6015C
6018 COMMON /SINFO/DELT,TIME,TINIT,TSTOP,IPRNT,IPL0T,NTIM,IGUT,IN
6021C
6024 COMMON /CONT/WA,WCOAL,WDOAL,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
6027 & COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDOAL1,OFF1,RETENT,XAVE,XAVE1,
6030 & UMIN(NX),T0TEFF,S02TOT,POWTOT,UTOT,DSTDM
6033C
6036 COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
6039 & THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
6042 & TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
6045C
6048 COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,R01,R1,R11,UEXP(NU),
6051 & XK(NX,NU),ALPHA,XMOLWT(7),S02EX,S02EX1,S02TEX,S02TEX1,
6054 & GDENS,GDENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
6057C
6060 COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WCO2,WCO21,
6063 & WN2,WN21,W02,W021,WH20,WH201,W02,W021,WPF0,WPF01,
6066 & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
6069C
6072 COMMON /GTURB/WT1,WT11,Q0,Q01,PT1,PT11,TTIC,TTIF,TEXC,TEXF,
6075 & DPFB,DPFB1,HPT,HPT1,XMWG,XMWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
6078 & HPC1,CPCD1,PRDROP,PRDROP1
6081C
6084 COMMON/STTURB/WS,WS1,QS,QS1,STHPRS,PGUT,PRSGUT,PSOUT,
6087 & PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
6090C
6093 TBEDA=TBED
6096 WABED=.9*WA
6099C
6102 HFREE=(HHV-327732.*COALPC(1)-92628.*COALPC(4))/1418970.75
6105C
6108C COMBUSTION PRODUCTS
6111C
6114 WH20=(.01*COALPC(6)*(1-REM)+.09*COALPC(2))*WCOAL*CEFF
6117 WN2=.01*COALPC(3)*WCOAL*CEFF+.7685*WABED
6120 WCO2=(.239*HCALC+.4783*TCALC)*FTOT+.03667*CEFF*COALPC(1)*WCOAL
6123 WS02P=.02*COALPC(4)*CEFF*WCOAL
6126 WH201=2.2046*WH20
6129 WN21=2.2046*WN2
6132 WCO21=2.2046*WCO2
6135 WS02P1=2.2046*WS02P
6138C
6141C STOICHIOMETRIC CONDITIONS
6144C
6147 WAS=(.11519*COALPC(1)+.0432*COALPC(4)+.34557*HFREE
6150 & -.01*COALPC(5))*WCOAL+7.72576*(R1-R0)
6153 WAX=WABED-WAS
6156 WAXPC=100.*WAX/WAS

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Figure B.9. Listing of the computer simulation. (Continued)

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```
6159      W02=.2315*WAX
6162      WAS1=2.2046*WAS
6165      WAX1=2.2046*WAX
6168      W021=2.2046*W02
6171C
6174C      GAS FLOWS
6177C
6180      WBED=WH2O+WN2+WCO2+WSO2P+W02
6183      WPFBG=WH2O+WN2+WCO2+WSO2+W02
6186      WBED1=2.2046*WBED
6189      WPFBG1=2.2046*WPFBG
6192C
6195C      GAS ENTHALPY & HEAT
6198C
6201      D0 10 NIT=1.50
6204      TBEDK=TBED+273.15
6207      CALL ENTH(WCO2,WN2,WSO2,W02,WH2O,TBEDK,H)
6210      QG=.001*H*WPFBG
6213      QG1=1.341*QG
6216C
6219C      HEAT IN STEAM
6222C
6225      DT1=TBED-TIN+DT
6228      DT2=TBED-TOUT+DT
6231      IF(DT2/DT1 .LT. 0.)PRINT,TIME,TBED,DT2,DT1
6234      IF (DT2/DT1 .LT. 0.) STOP
6237      DTM=(DT2-DT1)/ALOG(DT2/DT1)
6240      QS=1699.4*(1+.5*((TBEDK-1227.)/1227.))*DTM
6243      QS1=1.341*QS
6246C
6249C      CHECK HEAT BALANCE
6252C
6255      CP1=18.52+.02197*TBEDK-156800/(TBEDK*TBEDK)
6258      CP2=10.86+.001197*TBEDK-206700/(TBEDK*TBEDK)
6261      CP3=10.00+.00484*TBEDK-108000/(TBEDK*TBEDK)
6264      CPBED=.01313*(.44*CP1+.50*CP2+.06*CP3)
6267      QR=HHV*WCOAL+78468.75*WSO2P*RETENT-1526413.65*FTOT-CPBED*
6270      &      WTBED=(TBED-TBEDA)/DELT
6273      QR=.001*QR
6276      QR1=1.341*QR
6279      QSC=(1.-CLOSS)*QR-QG
6282      TBEDL=TBED
6285      TBED=(QS+QSC)*TBED/(2.*QS)
6288      TBEDF=1.8*TBED+32.
6291      PIN=4200.
6294      POUT=3500.
6297      TINF=1.8*TIN+32.
6300      TOUTF=1.8*TOUT+32.
6303      HIN=HPTL(PIN,TINF)
6306      HOUT=HPTD(POUT,TOUTF)
6309      WS1=2.682*QSC/(HIN+HOUT)
6312      WS=.4536*WS1
6315      IF(ABS(TBED-TBEDL) .LT. .05)GO TO 99
6318      10 CONTINUE
6321C
6324      99 RETURN
6327      END
```

LISTING OF FEP4/BEDINV

02/11/80 18.393

```
5000      SUBROUTINE BEDINV
5003C
5006C      UPDATES THE PARTICLE INVENTORY IN THE BED
5009C
5012      PARAMETER NX=11,NU=10
5015C
5018      COMMON /SINFO/DELT,TIME,TINIT,TSTOP,IPRNT,IPL0T,NTIM,IOUT,IN
5021C
5024      COMMON /CONT/WA,WCOAL,WDOL,XIOV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
5027      &      COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDOL1,OFF1,RETENT,XAVE,XAVE1,
5030      &      UMIN(NX),TOTEFF,SO2TOT,POWTOT,UTOT,DSTDM
5033C
5036      COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
5039      &      THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
5042      &      TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
5045C
5048      COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,R01,R1,R11,UEXP(NU),
5051      &      XK(NX,NU),ALPHA,XMOLWT(7),SO2EX,SO2EX1,SO2TEX,SO2TEX1,
5054      &      GDENS,GDENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
```

Figure B.9. Listing of the computer simulation. (Continued)

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5057C COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WC02,WC021,
5060 & WN2,WN21,W02,W021,WH20,WH201,WS02,WS021,WPFBG,WPFBG1,
5063 & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
5066
5069C
5072 COMMON /GTURB/WT1,WT11,Q0,Q01,PT1,PT11,TTIC,TTIF,TEXC,TEXF,
5075 & DPFB,DPFB1,HPT,HPT1,XMWG,XMWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
5078 & HPC1,CPCD1,PRDROP,PRDROP1
5081C
5084 COMMON/STTURB/WS,WS1,QS,QS1,STMPRS,POUT,PRSCUT,PSOUT,
5087 & PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
5090C
5093 DIMENSION DB(NX,NU),XOUT1(NX),XSTOR1(NX),XOUT2(NX),XSTOR2(NX)
5096 DIMENSION P(NX)
5099 DIMENSION XX(5)
5102C
5105C
5108C CALCINATION LAGS
5111C
5114 FTOT=0.
5117 ETOT=0.
5120 DO 10 N=1,NX
5123 IF(NTIM .GT. 1)GO TO 5
5126 XOUT1(N)=.009*PCC(N)*WDOL*TCALC
5129 XSTOR1(N)=.01*PCC(N)*WDOL*TCALC
5132 XOUT2(N)=.009*PCC(N)*WDOL*HCALC
5135 XSTOR2(N)=.01*PCC(N)*WDOL*HCALC
5138 5 CONTINUE
5141 WD1=.01*PCC(N)*WDOL*TCALC
5144 WD2=.01*PCC(N)*WDOL*HCALC
5147 XIN1=(WD1-XOUT1(N))/(.0001395*X(N)*X(N))
5150 XIN2=(WD2-XOUT2(N))/(.00001245*X(N)*X(N))
5153 XSTOR1(N)=XSTOR1(N)+DELT*XIN1
5156 XSTOR2(N)=XSTOR2(N)+DELT*XIN2
5159 XOUT1(N)=XSTOR1(N)+.5*DELT*XIN1
5162 XOUT2(N)=XSTOR2(N)+.5*DELT*XIN2
5165 F(N)=XOUT1(N)+XOUT2(N)
5168 FTOT=FTOT+F(N)
5171 10 CONTINUE
5174C
5177C PARTICLE BALANCE FOR EACH SIZE AND UTILIZATION
5180C
5183 DO 17 N=1,NX
5186 UTERM=SQRT(.00003038*X(N)*(BDENS-GDENS)/GDENS)
5189 RET=1E-2*UTERM*X(N)*GDENS/VISC
5192 IF (RET .GT. 500.) GO TO 15
5195 UTERM=.00002574*X(N)*((BDENS-GDENS)**2/(GDENS*VISC))**.333
5198 RET=1E-2*UTERM*X(N)*GDENS/VISC
5201 15 IF(RET .GE. .4)GO TO 16
5204 PRINT,'TIME,N,UTERM,RE=',TIME,N,UTERM,RET
5207 16 IF(US .GT. UMIN(N))E(N)=WBED*(.00012+130.*EXP(-10.4*SQRT(UTERM/US)
5210 & *(UMIN/(US-UMIN))**.25))
5213 IF(US .LE. UMIN(N)) E(N)=0.
5216 ETOT=ETOT+E(N)
5219C
5222 FINTOT=0.0
5225 P(N)=0.0
5228 DO 20 MM=1,NU
5231 DO 20 M=N+1,NX
5234 20 P(N)=P(N)+B(M,MM)/WTBED
5237 17 CONTINUE
5240C
5243 FMTOT=0.
5246 DO 21 MM=1,NU
5249 DO 21 M=1,NX
5252 21 FMTOT=FMTOT+P(M)*B(M,MM)
5255 XKA=.00000608*WTBED/FMTOT
5258C
5261 DX=X(1)-X(2)
5264 DO 30 J=1,NU
5267 DO 30 I=1,NX
5270 FF=0.
5273 FINTOT=0.
5276 IF(J .EQ. 1)FF=F(1)
5279 IF(I .NE. 1)GO TO 22
5282 DB(I,J)=FF+A(I)*TFINES-E(I)*B(I,J)/WTBED-B(I,J)*OFF/WTBED
5285 & -B(I,J)*XKA*P(I)*(US-UMIN(I))/(3*DX)
5288 22 IF(I .NE. NX)GO TO 24
5291 DB(I,J)=FF+A(I)*TFINES-E(I)*B(I,J)/WTBED-B(I,J)*OFF/WTBED
5294 & -B(I,J)*XKA*P(I)*(US-UMIN(I))/(3*DX)
5297 24 IF(I .EQ. 1 .OR. 1 .EQ. NX)GO TO 26
5300 DB(I,J)=FF+A(I)*TFINES-E(I)*B(I,J)/WTBED-B(I,J)*OFF/WTBED

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Figure B.9. (Continued)

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5303      &  -B(I,J)*XKA*P(I)=(US-UMIN(I))/(3.*DX)
5306  26  CONTINUE
5309      FINTOT=FINTOT+XKA*B(I,J)
5312  30  CONTINUE
5315      ETOT=ETOT+.9814*FINTOT
5318C
5321      WTBEDA=0.0
5324      DO 40 J=1,NU
5327      DO 40 I=1,NX
5330      B(I,J)=B(I,J)+DB(I,J)*DELT
5333      IF(B(I,J).LT.0.)B(I,J)=0.
5336  40  WTBEDA=WTBEDA+B(I,J)
5339C
5342C      MASS BALANCE
5345C
5348      FACT=(WTBED*(FTOT-ETOT-OFF)*DELT)/WTBEDA
5351      DO 50 J=1,NU
5354      DO 50 I=1,NX
5357  50  B(I,J)=B(I,J)*FACT
5360      WTBED=FACT*WTBEDA
5363      TFINES=FACT*FINTOT
5366      TFINES1=2.2046*TFINES
5369      WTBED1=2.2046*WTBED
5372      ETOT1=2.2046*ETOT
5375      FTOT1=2.2046*FTOT
5378C
5381      RETURN
5384      END
```

LISTING OF FEP4/GASTURB

02/11/80 18.393

```
7000      SUBROUTINE GASTURB
7003C
7006C      GAS TURBINE MODEL
7009C
7012      PARAMETER NX=11,NU=10
7015C
7018      COMMON /SINFO/DELT,TIME,TINIT,TSTOP,IPRNT,IPLDT,NTIM,IOUT,IN
7021C
7024      COMMON /CONT/WA,WCOAL,WDO1,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
7027      &  COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDO1,OFF1,RETENT,XAVE,XAVE1,
7030      &  UMIN(NX),TOTEFF,S02TOT,POWTOT,UTOT,DSTDMD
7033C
7036      COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
7039      &  THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
7042      &  TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
7045C
7048      COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,R01,R1,R11,UEXP(NU),
7051      &  XK(NX,NU),ALPHA,XMOLWT(7),S02EX,S02EX1,S02TEX,S02TEX1,
7054      &  GDENS,GDENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
7057C
7060      COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WCO2,WCO21,
7063      &  WN2,WN21,W02,W021,WH2O,WH2O1,WS02,WS021,WPF0,WPF01,
7066      &  WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
7069C
7072      COMMON /GTURB/WT1,WT11,QQ,QQ1,PT1,PT11,TTIC,TTIF,TEXC,TEXF,
7075      &  DPFB,DPFB1,HPT,HPT1,XMWG,XMWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
7078      &  HPC1,CPCD1,PRDROP,PRDROP1
7081C
7084      COMMON/STTURB/WS,WS1,QS,QS1,STMPRSS,POUT,PRSCOUT,PSOUT,
7087      &  PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
7090C
7093C
7096      TDROP=47.8
7099      IF (NTIM.EQ.1) TBD1=TBED-TDROP
7102      IF (NTIM.EQ.1) TTIC=TBED-TDROP
7105C
7108C      CALCULATE TURB INLET PRESSURE
7111C
7114      WT1=WT1+.0267*WA
7117      TBD=.05*DELT*(TBED-TDROP-TTIC)
7120      TBD1=TBD1+TBD
7123      TTIC=TBD1+.5*TBD
7126      TTIC=TTIC+273.15
7129      DO 10 NCNT=1,50
7132      PT1=WT1*(SQRT(TTIC))/27.31
7135C
7138C      CALCULATE TURBINE EXHAUST TEMPERATURE
7141C
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Figure B.9. (Continued)

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7144 GT02=WC02*WT1/WPFB0
7147 GTN2=WN2*WT1/WPFB0
7150 GTS02=WS02*WT1/WPFB0
7153 GTH20=WH20*WT1/WPFB0
7156 GTC02=WC02*WT1/WPFB0
7159 CALL SPHT(TTIC,WT1,GT02,GTN2,GTS02,GTC02,GTH20,CPT1)
7162 XMWT=14.515*GT02+12.708*GTN2+19.963*GTC02+8.172*GTH20+29.059*GTS02
7165 XMWT=XMWT/WT1
7168 RR=364.49/XMWT
7171 XJ=.101973
7174 EXPON=RR/(XJ*CPT1)
7177 TEXIK=TTIK*(111.285/PT1)**EXPON
7180 TEXIC=TEXIK-273.15
7183C
7186 CALL SPHT(TEXIC,WT1,GT02,GTN2,GTS02,GTC02,GTH20,CPTEX)
7189 HEXI=TEXIK-CPTEX
7192 HTI=TTIK-CPT1
7195 HEX=HTI-.95*(HTI-HEXI)
7198 TEXK=HEX/CPTEX
7201 TEXC=TEXK-273.15
7204C
7207C CALCULATE SYSTEM PRESSURE DROP
7210C
7213 DWBED=WPFB0-WT1-.0267*WA
7216 DPFB=.000135*DWBED*RR*(TBED+273.15)/XMWT
7219 PFB=PFB+DPFB
7222C
7225C CALCULATE NEW TURBINE INLET FLOW
7228 WT12=66.3*SQR(TPFB-PT1)
7231 RATIO=ABS((WT12-WT1)/WT12)
7234 WT1=.25*WT12+.75*WT1
7237 IF(RATIO.LT..001)GO TO 20
7240 10 CONTINUE
7243 IF(NCNT.GE.50)PRINT,'LOOP DID NOT CLOSE IN 50 ITERATIONS'
7246C
7249C CALCULATE TURBINE POWER OUTPUT
7252C
7255 20 HPT=.000001*WT1*(HTI-HEX)
7258C
7261 CALL COMPRESS
7264 XMWG=HPT-HPC-.6
7267C
7270C CONVERT OUTPUTS TO US UNITS
7273C
7276 WT1=WT1-.0267*WA
7279 WT11=2.2046*WT1
7282 PT11=PT1/6.895
7285 TTIF=1.8*TTIC+32.
7288 TEF=1.8*TEXC+32.
7291 PRDROP=PFB-PT1
7294 PRDROP1=PRDROP/6.894
7297 HPT1=1341.02*HPT
7300 XMWG1=1341.02*XMWG
7303 PFB1=PFB/6.894
7306C
7309C
7312 RETURN
7315 END
```

LISTING OF FEP4/COMPRESS

02/11/80 18.393

```
8000 SUBROUTINE COMPRESS
8003C
8006C AIR COMPRESSOR SIMULATION
8009C
8012 PARAMETER NX=11,NU=10
8015C
8018 COMMON /SINFO/DELT,TIME,TINIT,TSTOP,IPRNT,IPL0T,NTIM,IOUT,IN
8021C
8024 COMMON /CONT/WA,WCOAL,WDO1,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
8027 & COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDO1,OFF1,RETENT,XAVE,XAVE1,
8030 & UMIN(NX),TOTEFF,S02TOT,POWTOT,UTOT,DSTOMD
8033C
8036 COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCA1C,TCALC,F(NX),
8039 & THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
8042 & TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
8045C
8048 COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,RO1,RI,RI1,UEXP(NU),
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Figure B.9. (Continued)

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8051 & XK(NX,NU),ALPHA,XMOLWT(7),S02EX,S02EX1,S02TEX,S02TEX1,
8054 & GDENS,ODENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
8057C
8060 COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WC02,WC021,
8063 & WN2,WN21,W02,W021,WH20,WH201,WS02,WS021,WPFBG,WPFBG1,
8066 & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
8069C
8072 COMMON /GTURB/WT1,WT11,Q0,Q01,PT1,PT11,TTIC,TTIF,TEXC,TEXF,
8075 & DPFB,DPFB1,HPT,HPT1,XMWG,XMWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
8078 & HPC1,CPCD1,PRDROP,PRDROP1
8081C
8084 COMMON/STTURB/WS,WS1,QS,QS1,STMPRSS,PCUT,PRSCUT,PSOUT,
8087 & PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
8090C
8093C CALCULATION OF COMPRESSOR DISCHARGE PRESSURE
8096C
8099 TEMPC=301.667
8102 TEMPK=TEMPC+273.15
8105 PCD=PFB+21.2-.001*WTBED/AREABD
8108 GAM=286.927/CPCD1
8111 TAK=TAC+273.15
8114 TCDIK=TAK*((PCD/101.35)**GAM)
8117 TCDIC=TCDIK-273.15
8120 WAO2=WA*.2315
8123 WAN2=WA*.7685
8126 CALL SPHT(TCDIC,WA,WAO2,WAN2,0.,0.,0.,CPCD1)
8129 HCDI=TCDIK-CPCD1
8132 CALL SPHT(TAC,WA,WAO2,WAN2,0.,0.,0.,CPTA)
8135 HA=TAK-CPTA
8138 HCD=HA+1.1236*(HCDI-HA)
8141 TCDK=HCD/CPCD1
8144 TCDC=TCDK-273.15
8147C
8150C CALCULATION OF COMPRESSOR HORSEPOWER
8153 HPC=.000001*WA*(HCD-HA)
8156C CONVERT OUTPUTS TO US UNITS
8159 PCD1=PCD/6.895
8162 TCDF=1.8*TCDC+32.
8165 TAF=1.8*TAC+32.
8168 HPC1=1341.02*HPC
8171 RETURN
8174 END
```

LISTING OF FEP4/STMTURB

02/11/80 16.393

```
9000 SUBROUTINE STMTURB
9003C
9006C STEAM TURBINE MODEL
9009C
9012 PARAMETER NX=11,NU=10
9015C
9018 COMMON /SINFO/DELT,TIME,TINIT,TSTOP,IPRNT,IPL0T,NTIM,IGUT,IN
9021C
9024 COMMON /CONT/WA,WCOAL,WDO1,XIGV,HHV,PFB,PFB1,PTOT,PTOT1,OFF,
9027 & COALMOL(7),HHV1,CAS,WA1,WCOAL1,WDO1,OFF1,RETENT,XAVE,XAVE1,
9030 & UMIN(NX),TOTEFF,S02TOT,POWTOT,UTOT,DSTDMD
9033C
9036 COMMON /BEDIN/WTBED,AREABD,VOL,HT,HT1,B(NX,NU),HCALC,TCALC,F(NX),
9039 & THCALC,TTCALC,TFINES,FTOT,X(NX),A(NX),PCC(NX),E(NX),XKA,
9042 & TFINES1,WTBED1,ETOT,ETOT1,FTOT1,HTMF,HTMF1
9045 COMMON /SULFUR/COALPC(7),R,U(NX,NU),RO,R01,R1,R11,UEXP(NU),
9048 & XK(NX,NU),ALPHA,XMOLWT(7),S02EX,S02EX1,S02TEX,S02TEX1,
9051 & GDENS,ODENS1,BDENS,BDENS1,US,US1,UEFF,UEFF1,VISC,UMINN,UMINN1
9054C
9057 COMMON /HTBAL/WAS,WAS1,WAX,WAX1,QR,QR1,TBED,TBEDF,WC02,WC021,
9060 & WN2,WN21,W02,W021,WH20,WH201,WS02,WS021,WPFBG,WPFBG1,
9063 & WBED,WBED1,WAXPC,DT,TIN,TOUT,CEFF,CLOSS,REM,WS02P,WS02P1
9066C
9069 COMMON /GTURB/WT1,WT11,Q0,Q01,PT1,PT11,TTIC,TTIF,TEXC,TEXF,
9072 & DPFB,DPFB1,HPT,HPT1,XMWG,XMWG1,TAC,TAF,TCDC,TCDF,PCD,PCD1,HPC,
9075 & HPC1,CPCD1,PRDROP,PRDROP1
9078C
9081 COMMON/STTURB/WS,WS1,QS,QS1,STMPRSS,PCUT,PRSCUT,PSOUT,
9084 & PGV,PGV1,PM,PM1,FLOW(3),T(3),TSINC,TSOUTC,STEFF
9087C
9090C
9093C
9096 DIMENSION XIN(3),P(NX),PP(3)
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9099C
9102C      QSS1=WS1*(1100.4)
9105      QSS=.9478*QSS1
9108
9111C
9114      IF(NTIM.NE.1)GO TO 10
9117      QSCUT=QSS
9120      QSGV=QSS
9123      10 CONTINUE
9126C
9129C
9132      QSIN=(QSS-QSGV)/15.
9135      QSCUT=QSCUT+DELT*QSIN
9138      QSGV=QSCUT+.5*DELT*QSIN
9141      PGV=.001*QSGV
9144      PM=3*TEFF*PGV
9147C
9150C      CONVERSION TO US UNITS
9153      PGV1=1341.02*PGV
9156      PM1=1341.02*PM
9159C
9162      RETURN
9165      END
```

LISTING OF FEP4/SPHT

02/11/80 18.393

```
10000      SUBROUTINE SPHT(TIN,WIN,W02,WN2,WS02,WC02,WH20,CPTOT)
10003C
10006C      CALCULATE SPECIFIC HEAT OF GAS
10009C      COEFFICIENTS ARE FUNCTIONS OF DEG F
10012C
10015      TINF=1.8*TIN+32.
10018      CP02=7.18681+(.0010559*TINF)-(.16178*10.**(-6))*(TINF**2)
10021      CP02=CP02/32.00
10024      CPN2=6.45987+(.0012548*TINF)-(.18569*10.**(-6))*(TINF**2)
10027      CPN2=CPN2/28.016
10030      CPC02=9.33007+.0038139*TINF-(.80300*10.**(-6))*(TINF**2)
10033      CPC02=CPC02/44.01
10036      CPH20=7.50428+.0018646*TINF-(.83624*10.**(-7))*(TINF**2)
10039      CPH20=CPH20/18.016
10042      CPS02=0.154
10045      CPTOT=(W02*CP02/WIN)+(WN2*CPN2/WIN)+(WC02*CPC02/WIN)+
10048      (WH20*CPH20/WIN)+(WS02*CPS02/WIN)
10051C
10054C      CONVERT TO JOULES/KG-K
10057C
10060      CP02=4186.8*CP02
10063      CPN2=4186.8*CPN2
10066      CPH20=4186.8*CPH20
10069      CPS02=4186.8*CPS02
10072      CPC02=4186.8*CPC02
10075      CPTOT=4186.8*CPTOT
10078C
10081      RETURN
10084      END
```

LISTING OF FEP4/ENTH

02/11/80 18.394

```
11000      SUBROUTINE ENTH (WC02,WN2,WS02,W02,WH20,TEMP,H)
11003C
11006C      ENTHALPY (J/KG) AS FCT OF TEMP (DEG K)
11009C
11012      DIMENSION C1(5),C2(5),C3(5),HH(5)
11015C
11018      DATA C1/-322695.9,-298568.8,-237617.4,-297095.9,-504604.9/
11021      DATA C2/940.759,966.303,710.112,929.668,1604.893/
11024      DATA C3/.14227,.09913,.06331,.07757,.34326/
11027C
11030      DO 10 N=1,5
11033      10 HH(N)=C1(N)+C2(N)*TEMP+C3(N)*TEMP*TEMP
11036C
11039      H=(WC02*HH(1)+WN2*HH(2)+WS02*HH(3)+W02*HH(4)+WH20*HH(5))/
11042      & (WC02+WN2+WS02+W02+WH20)
11045C
11048      RETURN
11051      END
```

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Figure B.9. (Continued)

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GLOSSARY COMPUTER MODEL

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A: Total fines created by attrition in each size range, kg/s

ALPHA: Measure of excess air, unitless

AREABD: Bed area, m²

ARNO: Archimede's Number, unitless

B: Mass of bed material in each size and utilization, kg

BDENS: Solids density, g/cm³

BDENS1: Solids density, lb/ft³

BLRDMD: Boiler power demand, fraction of design case

BUFF: Buffer space used to create plot file

BXX: Mass of dolomite changing utilizations during calculation interval, kg

CAS: Ca/s feed ratio

CATFILE: Catalog/file description

CC1, CC2, CC3, CC4: Coefficients

CEFF: Combustion efficiency, fraction

CLOSS: Energy losses throughout system, fraction

COALCOMP: Coal composition, a list of the elements

COALMOL: Moles of each component in the coal

COALPC: Percent of each component in coal (by weight)

CPCDI: Ideal specific heat of the compressor discharge, J/kg-°C

CPH20: Specific heat of H₂O, J/kg-°C

CPN2: Specific heat of N₂, J/kg-°C

CP02: Specific heat of O₂, J/kg-°C

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CPS02: Specific heat of SO_2 , $\text{J/kg-}^\circ\text{C}$

CPTA: Specific heat of ambient air, $\text{J/kg-}^\circ\text{C}$

CPTOT: Specific heat of total flow, $\text{J/kg-}^\circ\text{C}$

DD1, DD2, DD3: Coefficients

DELT: Time step, seconds

DEMAND: Power generation demand signal, MW

DOLODMD: Dolomite feed rate demand, kg/s

DPFB: Pressure drop from the combustor to the turbine inlet nozzle, kPa

DPFB1: Pressure drop from the combustor to the turbine inlet nozzle, PSI

DSTD: Change in power required to meet demand, MW

DSTDMD: Change in steam turbine demand from what is currently being produced, MW

DT: Temperature drop through the walls of the steam tubes in the bed, $^\circ\text{C}$

E: Elutriation for a given particle size, kg/s

ERTBED: Error in bed temperature, i.e. set point - actual, $^\circ\text{C}$

ETOT: Total elutriation from the bed, kg/s

ETOT1: Total elutriation from the bed lb/sec

F: Feed rate of freshly calcined dolomite of a given size, kg/s

FACT: Ratio of bed weight at previous calculation interval to current weight

FLOW: Flow of steam into the steam turbine, kg/s

FTOT: Total feed rate of freshly calcined dolomite, kg/s

FTOT1: Total feed rate of freshly calcined dolomite, lb/sec

GDENS: Gas density, g/cm^3

GDENS1: Gas density, lb/ft^3

GTCO2: CO_2 entering gas turbine, kg/s

GTH20: Water entering gas turbine, kg/s

GTN2: N_2 entering gas turbine, kg/s

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GT02: O₂ entering gas turbine, kg/s

GTSO2: SO₂ entering gas turbine, kg/s

H: Enthalpy of each component, J/kg

HH: Enthalpy of entire stream, J/kg

HHV: Higher heating value of coal, J/kg

HHV1: Higher heating value of coal, BTU/lb

HPC: Power required to drive the air compressor, MW

HPCL: Power required to drive the air compressor, HP

HPT: Power produced by gas turbine, MW

HPT1: Power produced by gas turbine, HP

HT: Bed height, m

HT1: Bed height, Ft

HTDMD: Bed height error demand, m

HTMF: Bed height at minimum fluidizing conditions, m

HTMF1: Bed height at minimum fluidizing conditions, Ft

I: Index of sizes

IN: File code from which to read input

INTTIM: Integer representation of time, Hours

IOUT: File code to which output is written

IPLLOT: Number of calculation intervals between records written to plot file

IPRNT: Number of calculation intervals between sets of output

J: Index of utilizations

NTIM: Number of calculation interval

NU: Number of utilizations

NX: Number of sizes

OFF: Offtake rate, kg/s

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OFF1: Offtake rate, lb/sec
OFFREG: Offtake rate demand, kg/s
PCC: Percent of dolomite in each size
PCD: Compressor discharge pressure, kPa
PCD1: Compressor discharge pressure, PSI
PFB: Pressure in fluidized bed, kPa
PFB1: Pressure in fluidized bed, PSI
PGV: Power entering steam turbine, MW
PGV1: Power entering steam turbine, HP
PLTFIL: Plot file
PM: Power produced by steam turbine, MW
PM1: Power produced by steam turbine, HP
POUT: Steam pressure leaving combustor tubes, kPa
PTI: Gas turbine inlet pressure, kPa
PTI1: Gas turbine inlet pressure, PSI
PTOT: Total power produced by system, MW
PTOT1: Total power produced by system, HP
QG: Thermal energy entering gas turbine, KW
QG1: Thermal energy entering gas turbine, HP
QR: Heat of reaction, KW
QR1: Heat of reaction, HP
QS: Heat available to steam, KW
QS1: Heat available to steam, HP
R: SO₂ retention, %
RO: Sulfur leaving combustor, kg-moles/s
RO1: Sulfur leaving combustor, lb-moles/sec

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REM: Fraction of water removed in coal dryer
RI: Sulfur entering bed, kg-moles/s
RI1: Sulfur entering bed, lb-moles/sec
SO2EX: Sulfur leaving bed, kg/J
SO2EX1: Sulfur leaving bed, lb/BTU
SO2TEX: Total sulfur leaving bed during whole run, kg/J
SO2TEX1: Total sulfur leaving bed during whole run, lb/BTU
SO2TOT: Total sulfur leaving bed, kg/s
SPTBED: Set point of bed temperature, fraction of design point
STDMD: Steam turbine demand, MW
STEFF: Steam turbine efficiency, %
STMPRSS: Steam pressure entering turbine, kPa
TAC: Ambient air temperature, degrees C
TAF: Ambient air temperature, degrees F
TBED: Bed temperature, degrees C
TBEDF: Bed temperature, degrees F
TCALC: Fraction of dolomite which will reach total calcination
TCDC: Compressor discharge temperature, degrees C
TCDF: Compressor discharge temperature, degrees F
TEXC: Turbine exhaust temperature, degrees C
TEXTF: Turbine exhaust temperature, degrees F
TFINES: Total fines produced, kg/s
TFINES1: Total fines produced, lb/sec
TIME: Calculate time, seconds
TIN: Temperature of steam entering combustor, degrees C
TINIT: Initial time of analysis, seconds

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TITLE: Title of run

TOTEFF: Total efficiency of plant, %

TOUT: Steam temperature leaving bed, degrees C

TSTOP: Stop time of simulation, seconds

TTIC: Gas turbine inlet temperature, degrees C

TTIF: Gas turbine inlet temperature, degrees F

U: Utilization, %

UEFF: Effective velocity, m/s

UEFF1: Effective velocity, Ft/sec

UEXP: Expected utilization, %

UMIN: Minimum fluidization velocity of a given size, m/s

UMINN: Minimum fluidization velocity of entire population, m/s

UMINN1: Minimum fluidization velocity of entire population, Ft/sec

UNUM: User identification

US: Superficial velocity, m/s

US1: Superficial velocity, Ft/sec

UTOT: Average utilization of entire bed, %

VISC: Viscosity of gas, kg/m-s

VOL: Volume, m³

WA: Air flow rate, kg/s

WA1: Air flow rate, lb/sec

WAS: Air required for stoichiometric combustion, kg/s

WAS1: Air required for stoichiometric combustion, lb/sec

WAX: Excess air, kg/s

WAX1: Excess air, lb/sec

WAXPC: Percent excess air

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WBED: Gas flow rate through bed, kg/s

WBED1: Gas flow rate through bed, lb/sec

WCO2: Flow rate of CO₂, kg/s

WCO21: Flow rate of CO₂, lb/sec

WCOAL: Flow rate of coal, kg/s

WCOAL1: Flow rate of coal, lb/sec

WDOL: Flow rate of dolomite, lb/sec

WDOL1: Flow rate of dolomite, kg/s

WH2O: Flow rate of water, kg/s

WH2O1: Flow rate of water, lb/sec

WN2: Flow rate of N₂, kg/s

WN21: Flow rate of N₂, lb/sec

WO2: Flow rate of O₂, kg/s

WO21: Flow rate of O₂, lb/sec

WPFBG: Flow rate of gas leaving the combustor, kg/s

WPFBG1: Flow rate of gas leaving the combustor, lb/sec

WS: Flow rate of sulfur, kg/s

WS1: Flow rate of sulfur, lb/sec

WSO2: Flow rate of SO₂ leaving bed, kg/s

WSO21: Flow rate of SO₂ leaving bed, lb/sec

WSO2P: Flow rate of SO₂ entering bed, kg/s

WSO2P1: Flow rate of SO₂ entering bed, lb/sec

WTBED: Weight of bed, kg

WTBED1: Weight of bed, lb

WTI: Turbine inlet flow, kg/s

WTI1: Turbine inlet flow, lb/sec

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X: Sizes of dolomite particles, microns

XAV: Average particle size, microns

XAV1: Average particle size, inches

XIGV: Inlet guide vane setting, fraction open

XIGVDM: IGV demand signal, fraction of set point

XK: Reactivity rate of bed, per second

XKA: Attrition rate constant, per meter

XKT: Thermal factor of reactivity rate

XKX: Size factor of reactivity rate

XMOLWT: Molecular weight of gas

XMWG: Gas turbine power generation, MW

XMWG1: Gas turbine power generation, HP

XTIM: Time, real number, Hours

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